BEFORE THE

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

- - - - - - - - - - - - - - - - x

In the matter of: :

Review of Small Generator : Docket Number

Interconnection Agreements : AD12-17-000

And Procedures Technical :

Conference :

- - - - - - - - - - - - - - - - x

Commission Meeting Room 2C

Federal Energy Regulatory Commission

888 First Street, Northeast

Washington, D.C. 20426

Tuesday, July 17, 2012

The technical conference was convened, pursuant to notice, at 9:03 a.m.

STAFF ATTENDEES:

Leslie Kerr, presiding

Arnie Quinn Christy Walsh

Elizabeth Arnold Michelle Davis Tom Dautel

Thanh Luong Monica Taba

Melissa Lozano

P R O C E E D I N G S

9:04 a.m.

MS. KERR: Good morning, and thank you all for joining us today to share your views on and experiences with small generator interconnection. This technical conference was prompted by the Solar Energy Industry Association's petition for rulemaking, to update the Commission's pro forma small generator interconnection agreements and procedures.

In Order No. 2006, the Commission encouraged interested entities to continue to work together on small generator interconnection issues. This technical conference is convened to explore possible reforms to the SGIA and SGIP, to address the issues raised by the SEIA.

This morning, we will discuss two aspects of the Fast Track process in the pro forma SGIP. Specifically, we will discuss the 15 percent screen in Section 2.2.1.2 of the SGIP, and the two megawatt eligibility threshold for participation in the Fast Track process.

This afternoon, we will have two additional panels. The first panel will discuss collection and sharing of peak and minimum load data. The second panel will discuss review of upgrades required for interconnection.

We will begin with a five minute opening statement from each of our panelists. After the opening statements, we will have questions from staff and perhaps from Commissioners. We intend for this to be an active discussion of possible reforms to the SGIP and SGIA, and to that end, hope that panelists will explore with us possible regulatory alternatives that could address the issues raised by SEIA, and that are consistent with the Commission's statutory responsibilities.

For those of you watching the live webcast or listening by phone, some of our speakers submitted materials in advance of the conference. Those materials and the agenda are available on the Commission's website. We plan to break for lunch around 11:30 and reconvene for the second panel at 1:00. We plan to wrap up the conference around 4:00 this afternoon.

Restrooms are available at either end of the hallway behind the elevators. Building management has asked me to remind everyone that only water and no other food or beverages are permitted in the Commission meeting room.

Now I would like to welcome Commissioner Norris. Commissioner, do you have any remarks?

COMMISSIONER NORRIS: Thank you. Let me just welcome everybody. I appreciate you being here today to share with us, and we thank SEIA for bringing this issue to our attention, or raising the profile of this issue, if you will.

I think this is just a good example of how we have new technologies that are providing new opportunities, but operate different than some of the technologies we had had in the past.

So how do we adapt and change operations and rules to take advantage of those new resources? That's how I view this issue. So I think you've raised some good issues about how we -- let's look at the operations, the 15 percent rule, SGIP, the two megawatt rule, and figure out how to make this work so we capitalize on what I think is just an emerging solar industry in this country.

I think the costs for solar are going to come down. It's going to become more pervasive as an energy resource from the DG level to the large scale level. How do we make changes in operation to accommodate this and capitalize on it and get it right.

So that's what I'm hopeful to learn from what I hear today, and of course you'll be building a record that I'll be reviewing with the other Commissioners as well. So thanks for all of you taking your time to give us input.

MS. KERR: Thank you, Commissioner. Now I'd like to introduce the staff at the table. To my left are Arnie Quinn and Christie Walsh will be joining us a little later. Elizabeth Arnold, Michelle Davis and Rachel Bryant. To my right are Tom Dautel, Thanh Luong, Monica Taba and Melissa

Lozano.

With that, excuse me, I believe we're ready to start the first panel. I would like to remind the panelists to please turn the microphone on in front of you when you're speaking, and turn it off when you're not.

Please also turn your cell phones off when the microphone is on, as they can interfere with the mics. Of course, everyone in the audience, including the audience, please turn off the ringers on your cell phones.

The panelists we're happy to have with us here today are Virinder Singh from enXco, on behalf of the SEIA; Carl Lenox from SunPower Corporation, on behalf of SEIA; Michael Coddington from the National Renewable Energy Laboratory; Tim Roughan from National Grid, on behalf of Edison Electric Institute; Steve Steffel from Atlantic City Electric; Jeffrey Triplett, Power System Engineering, on behalf of the National Rural Electric Cooperative Association; Jose Carranza from San Diego Gas and Electric; Michael Sheehan, Keyes, Fox and Wiedman on behalf of the Interstate Renewable Energy Council; and Rachel Peterson from the California Public Utilities Commission.

Now I'd like to invite our first panelist, Virinder Singh, to give his opening statement.

MR. SINGH: Thank you, Leslie. Okay. First of all, we'd really like to thank FERC Commissioners, FERC staff for holding this technical conference and paying attention to this issue. We think it's a very important issue.

My name is Virinder Singh. I'm Director of Regulatory and Legislative Affairs for enXco. We are a development company headquartered in San Diego. We are constructing or have developed about 180 megawatts of solar and about 4,600 megawatts of wind, and we're engaged in some other technologies.

We think this is a very important issue, and I'd just like to provide some broader context before people who are more engineering oriented, take over the discussion a little bit more as is appropriate.

Since Order 2006 was issued in 2005, growth in solar generation capacity has been absolutely dramatic, fueled in part by certain state level policies, federal incentives and declining prices. Overall in the U.S., grid-tied solar photovoltaic PV capacity grew from 230 megawatts in 2005 to approximately 2,100 megawatts in 2011, or a ninefold increase. Total PV generation capacity now is approximately 4,400 megawatts.

The states with the most active sola markets are those that also have the most assertive policies, including rebates, requirements, net metering and specific procurement programs. According to Lawrence Berkeley National Lab, up to 80 percent of grid-connected solar outside of California occurred in states that they deem as having the most active or impending solar requirements.

Some quick examples. New Jersey now has 15,778 PV projects installed in the state, totaling 770 megawatts, with another 510 megawatts in the pipeline, meaning it's in review or there's a commitment letter issued for those projects. California has 1,000 megawatts of customer-generated solar generation at 122,000 sites.

They've also begun a wholesale generation procurement program totaling 1,000 megawatts called the renewable option mechanism, and they have a feed-in tariff program that totals 750 megawatts. Hawaii has 96 megawatts of PV generation installed through the first quarter of this year. 71 megawatts of that was installed over the last two years.

Massachusetts has a 400 megawatt solar requirement, with expectations of rapid uptake over the next several years, that we don't have Q data. Hopefully we will down the road. Finally, Arizona has 448 megawatts of total installed solar generation capacity by the end of the first quarter of this year, with the vast majority of that, almost 400 megawatts, installed in the last two years alone.

Consequently, we are seeing areas where circuits are indeed being "walled off," so to speak, from further generation, absent cost-prohibitive upgrades. In Hawaii, approximately ten percent of circuits now trigger studies at the 15 percent of peak level.

A Green Wire report compared the Islands maps with red-coded circuits, indicating circuits that require extensive study, as making the Islands look like they're coming down with the chicken pox. In California, areas with particularly strong development characteristics, such as having available land that can be legally converted to solar generation from agriculture, has resulted in a concentration of wholesale DG development in counties such as Kern and Tulare in the Central Valley.

Developers are now hearing about circuits that are essentially walled off absent extensive study, and the need to build new lines to accommodate the project Q in these counties. FERC has recognized the importance of grid planning in the context of state level RPSs, as evidenced in Order 1000, which formally takes state renewable portfolio standards into consideration, in terms of transmission planning.

Similarly, we have arrived at a moment in the solar industry where all stakeholders must revisit old assumptions about what the grid can handle, and how the grid has managed to ensure reliability amid a new state level emphasis on small-scale clean power generation.

In Order 2006, FERC stated that the SGIP and the SGIA must be revisited periodically, and not less than once every two years. Stakeholders, including SEIA, did not revisit both until now, and due directly to the material impact that the 15 percent of peak threshold is beginning to exert on implementation of state-level energy policy priorities.

We must revisit. States such as California, Hawaii and New Jersey have already recognized a need to revisit old assumptions, to avoid undue discrimination towards what are relatively new market entrants in the U.S. power generation sector.

We applaud these efforts. We also believe that national models from FERC can be extremely helpful in leveraging these efforts, and informing future discussions in other states that may place a higher priority on distributed solar generation.

California's Rule 21 reforms provide the most extensive model that is appropriate for balancing the public's focus on increasing solar generation, with essential reliability considerations. Regarding the two megawatt cap on Fast Track interconnection, we support a standard that relates to the overall screen of 100 percent of minimum load.

That is, Fast Track should be allowed for projects that do not exceed the 100 percent of minimum load on individual circuits. Also note that the California Independent Systems Operator has asserted a five megawatt project size cap for Fast Track.

The 100 percent of daytime minimum load standard is still conservative in avoiding reverse power flows. Daytime load will almost always be higher than night time load, so the standard sets a bar above absolute minimum load.

Finally, I want to emphasize that the 15 percent of peak limit would still where interconnection requests are not approaching the cap, which are in plenty of places in the United States. So effectively, the revisions we are seeking would not affect broad swaths of the U.S. in the near future. The current standard would only need to be revisited when its effect is becoming material on both state policy implementation, as well as ratepayer cost.

I guess finally, I want to refer back to this Green Wire study report on Hawaii. Somebody called the current 15 percent of peak load cap "a conservative assumption of a conservative assumption." This leads to two results. A, an over-investment in distribution infrastructure, with attendant ratepayer costs.

Assuming that costs are ultimately foisted on projects, costs ultimately foisted on projects will get reflected in market prices that are paid by ratepayers. Second, we risk a potential short-circuiting of state clean energy policies. Thank you for your time.

MS. KERR: Thank you. Carl Lenox is next.

MR. LENOX: Hi. I'm Carl Lenox from SunPower, representing SEIA. I just have a few brief comments this morning. Thanks very much again for the opportunity to address this issue. It's a very important issue for our industry.

And at the outset, I want to make clear that grid reliability and safety are, of course, of paramount concern to everyone, and the PV industry has no incentive to negatively impact reliability and safety. That context is really critical as we move forward.

However, the existing 15 percent of peak load screen does result in too many projects, which are technically viable, unnecessarily being placed into a costly study process. This can be frustrating for developers. It often kills a lot of projects, and it can increase utility workloads.

The screen that's being proposed here helps to better define the interconnection process. It's part of a larger supplemental review process, and passing the screen does not automatically interconnection. So incorporating 100 percent of minimum load screen by itself really just helps to create a more structured supplemental review process.

Changing the screen will not negatively impact grid reliability or safety. The main concern is that changes to the 15 percent of peak load screen can result in unintentional islanding within the distribution system. We have put together and circulated a Tentacle white paper, which discusses why this is not the case in some detail. That's available on the back table, and I can also speak to it today.

Empirically, we have not seen any evidence of unintentional islanding issues, even in markets where much higher distribution system penetrations are routine. For instance in Germany, where penetrations in excess of 100 percent of daytime minimum load are routine and in fact reverse power flow is quite routine, we have not seen this issue.

In fact, in that country, in the spring of this year, we've seen up to 40 percent of the total electricity demand in the country served by PV predominantly, the vast majority of which was distributed PV. Just as a small commentary, we've actually seen PV installed in our country at a clip of a gigawatt per month or greater.

We've also seen that the CPUC and the California IRUs have agreed with the solar industry, that the supplementary screen will streamline the interconnection process without negatively impacting safety and reliability.

So I would just conclude that SEIA urges FERC to consider adding the supplemental screen to the small generator interconnection process. Thank you.

MS. KERR: Thank you, and Michael Coddington is next.

MR. CODDINGTON: Well good morning. Thank you, Leslie, Commissioner Moeller and good morning everyone. I'd like to give you a little background on the recent report published last January by Embril, Sandia National Laboratories, EPRI and the Department of Energy, titled "Updating Interconnection Screens for PV System Integration."

It's nice to see that there are four of my co-authors in the audience today, representing each of the organizations. So during the early development of interconnection standards, there was a great concern that the load on distribution feeders will always be greater than the amount of DG on that feeder, primarily to reduce the chance of an unintentional island.

So it's necessary for utility engineers to understand what that minimum load level was, so they could limit the amount of DG on the circuit. Very few, if any, utilities actually tracked minimum load data, but virtually all utilities do track peak annual load data on circuits.

And speaking from experience, 20 years in the utility industry, that's something I did on a very regular basis. It's how utilities plan and build new circuits when that's needed to serve load. So in order to approximate the minimum load level, engineers use a rule of thumb in which minimum load is approximately 30 percent of peak load.

If you cut that 30 percent in half, you get a very conservative number that is sure to be lower than the true minimum load. Now I'm all for rules of thumb and engineering. I mean they're great for, you know, trying to understand what the answer's going to be before you do a detailed study.

But you know, as long -- you know these rules of thumb are great as long as they are based on solid technical rationale, and I don't believe that this 15 percent penetration screen really meets that criteria. It tends to be a one-size-fits-all rule for all feeders.

When we talk about photovoltaic systems, we should be concerned about the minimum load during the period of maximum PV generation, which is referred to as "solar noon," and that's going to be between 10:00 a.m. and 2:00 p.m.

So there are numerous case studies and testimonies, which you've heard already some testimony, of large PV systems that have been through detailed studies, without need for any system modifications.

We've seen circuits operating at penetration levels of well over 50 percent, which seems to be more than anecdotal evidence that penetration may not be a limiting factor in deploying PV systems.

I believe that the 15 percent of peak load could be improved as a short-term solution methodology. Moving toward the minimum daytime load for PV system screening seems like a reasonable approach, as long as that system data is available.

Longer-term solutions, which I think is ultimately where we need to focus our efforts, we'll see advanced inverter technology and Smart Grid systems improve the landscape for interconnecting PV. So for the short term, I believe using minimum daytime load information, again if available, is a reasonable next step in improving the small generator interconnection procedures.

Most utilities use a SCADA system to gather their load information, and many of those SCADA systems have the capability to capture a defined history for each feeder, and again, I speak from experience.

That should include capturing minimum daytime load between the hours of 10:00 a.m. and 2:00 p.m. if possible. I believe that utilities could utilize minimum daytime load as a significant improvement over this peak data, again if that data can be realized.

I also believe that using supplemental review screens could be a very helpful approach, primarily to assist electric utilities in getting through some of their queue of interconnection requests.

Supplemental screens should look at issues such as voltage levels, location of the proposed system, the impedance at that location and perhaps the available fault current level at that proposed location. It's complex, that's for sure.

As the far the question of two megawatts is concerned, I struggle with that number. I think there's a question on the table about whether that should be changed. A seasoned engineer once told me, when I was quite a bit younger, that I should have a good idea of what the answer should be before I do the study.

I understand now what he meant, and when I see a system in the megawatts, that certainly is a red flag that I want to look at a system that is that large. But that's my personal experience speaking. So for the long term, I see improved methods for integrating high PV on the distribution grid, that includes sophisticated modeling systems that are fast, and require much less time than the systems we use today.

Think of using a PV interconnection easy button, as it were, with an advanced study tool, and certainly the national labs, the Department of Energy, groups like EPRI are working diligently to develop such tools. Finally, advanced inverters, electrical storage systems, robust communications and control and a more intelligent grid will all be part of the long-term solutions. Thank you.

MS. KERR: Thank you, and next we have Tim Roughan.

MR. ROUGHAN: Thank you, and I want to thank the FERC for hosting us here today. It's almost ten years ago this summer that we had this same discussion, relative to small gen procedures, and at the time, there was proposals put forth by the industry suggesting various changes.

At the time, it was very important that we all work together as a group, to come up with what then became the operative Order 2006. I think the main purpose of my comments representing EEI is the same process really does need to be followed. I think there's lots of different utilities at different places in terms of interconnecting large amounts of solar.

California utilities, up in the Northeast and Massachusetts, for example, just to help the first speaker. We have over 850 megawatts of solar proposed, and about 115 megawatts installed in Massachusetts. That 850 megawatts has come about in just the last two years.

Two years ago, the largest project we were seeing looking to be interconnected in Massachusetts were 50 kilowatts, 100 kilowatts. Now it's fairly routine to get three, four, five megawatt proposals on the local distribution, local distribution circuits that feed three to five thousand other customers.

The key point of doing the interconnection analysis, whether with screens or reviews, is to make absolutely sure that once that system is interconnected and operating, that it does not affect the customers next door. This is a very different animal from larger projects that typically have interconnected to transmission level and larger and higher voltage systems. When you're connecting to local 12 and 13 kV systems, you really have to recognize that there are significant issues out there.

Most of the solar projects that we're seeing in Massachusetts and Rhode Island, because they have similar subsidies now, are out at the fringes of our distribution system, because that's where the land is available and inexpensive to build these projects.

Had they been proposed in the load centers, very different things could occur. But because of where they're being proposed, it causes significant issues relative to again, the neighbor's power quality and their reliability as well.

So it's important to recognize that at a high level, and I see today as a repeat of ten years ago, where we really need to get together with the industry, as the electric utilities come up with a plan as to how to move forward and potentially modify the small gen procedures.

Because it's very important as we go forward to continue to support the states that we all work in. You know, EEI and National Grid and the utilities are very supportive of the state policies that are promoting renewable energy, and we have been engaged specifically in the legislative process to get those policies and procedures put into place.

And working together with the industry, we can come up with ways to streamline the process. But I think it is premature to simply change the rules because today, it appears that it's getting more difficult to interconnect solar. It's more difficult simply because of the size of the projects are so dramatically different than just a few years ago for many parts of the country.

When you're talking four megawatts on a circuit that typically has a peak load of five or six megawatts, it's a significant impact. The issue of minimum loading is also concerning to us, because again, it will and can affect the flexibility of the system going forward, if you now have to maintain a certain amount of minimum load on a circuit out there.

The 50 percent limit was put in place as a conservative level, to make sure we wouldn't affect the neighbors, and going forward, whether that needs to be adjusted or changed is again part of a consensus-building effort that I think we should probably embark on going forward.

Because there's many issues that do need to be looked at. You know, we are all working through how we're going to increase the reliability and safety of our systems through additional intelligence and communications, the Smart Grid, if you will.

As we go forward, we need to understand how we need to modify some of those proposals that are already in front of some regulators, in terms of how to accommodate additional amounts of renewables, whether it be solar, wind, landfill gas, biomass, etcetera. There's lots of other opportunities out there which we really need to properly address.

And in terms of the two megawatt value, again we're talking circuits where in the locations they're being proposed, the peak loads aren't very much higher than the two megawatts. So you really need to get into the details of the review, to make sure that when you're done with the review and it goes online, it will not affect the neighbors' reliability and power quality safety.

Because once they're online, there's not anything we can do about them. So we need to be absolutely sure, when we're done with our studies, that what we've agreed to through the interconnection agreements will provide for a highly reliable system, that will produce all the benefits of renewable energy which the states and the country need, but conversely also work well with the utility distribution system in the area, to maintain that high level of reliability that our customers have grown so accustomed to over the past few decades. Thank you.

MS. KERR: Thank you, Tim. Next we have Steve Steffel from Atlantic City Electric.

MR. STEFFEL: Thank you very much for the opportunity. I'm Steve Steffel with PEPCO Holdings, Inc. Atlantic City Electric is one of our utilities, as well as Delmarva Power in the PEPCO area, right here in Washington, D.C. All of our areas are experiencing solar integration. We've got about 150 megawatts total right now, and increasing rapidly.

We do support solar integration. We've made the SEPA Top Ten List with Atlantic City Electric for the last couple of years, and while PHI supports increased solar and other distributed energy resource additions, and we do have a number of other ones that apply to and we have to accommodate all of them, we remain focused on maintaining a reliable grid for customers.

PHI is supporting a lot of the efforts that develop advanced technology. In inverters, we've already worked with one inverter company to develop new software. We're working on advanced modeling programs so that we can actually assess grid impact very quickly for applications. We have measurement data collection systems out there. We're working on new communications.

We want to accommodate all the renewables that want to come on the grid safely and reliably. One of the things, though, that is a takeaway, if we do have installations that cause negative impacts on the grid, it will ultimately hurt the solar industry or those industries that are attempting to put that type of equipment on the grid.

We do have a lot of pending systems, and so that's some of our focus. One of the things I'd like to mention and point out, and it is available in the handouts, but we're just going to touch on some of the highlights, on hosting capacity.

EPRI just did a recent study on one of our rural feeders, and the study came back that the minimum hosting capacity could be as low as 3.3 percent, depending on where you put the inverter-based systems, the solar systems.

Then they compared it to an urban feeder, and the urban feeder was similar voltage, similar load and peak. Had a much, much different, much higher hosting capacity. So this is something that we've got to keep in mind, is that there are all kinds of feeders out there with different characteristics and different hosting capacities.

One example I'll give, and it's also on our handout, we just experienced that. We have a system that 1.3 megawatt AC PV system, 1.8 miles out from the substation. This particular feeder, we know that typically it's around 30 percent the minimum load to the peak load.

But this particular feeder had a 15 percent daytime minimum load. It's quite an anomaly. There's not a lot of feeders like that, but this one had a lot of industrial customers. So we experienced in the spring time, when you typically have your maximum output, there was some reverse flow on this feeder.

It wasn't anticipated by our planning engineers and it had passed the screens, and it had gone in without any detailed study. Well, it caused reverse flow on a voltage regulator right outside the substation. That regulator went to maximum raised position on the feeder, and it caused damaging high voltage for several closer-in customers.

Even though the inverters tripped later on at the solar site, the closer-in customers experienced high voltage and actually resulted in significant damage to equipment. So it is very possible to have that condition, and there's other, many other feeders, irrigation feeders, different types that have loads that area not predictable.

Economic changes. These particular industrial loads on this feeder probably operated seven days a week, cut back on the weekends, and resulted in this situation. One of the other things is that this can occur on any feeder, where you have a voltage regulation zone.

If you don't have the voltage regulator set up for reverse flow from a co-gen unit or a PV unit, you can experience the same problem, and there's voltage regulators on feeders that haven't been set up for this type of phenomena. So you can have little ones, big ones that cause that.

In summary, the 15 percent screen is good for the vast majority of circuits, and should be maintained. However, it should not be viewed as a failsafe screen, and utilities should have the discretion of doing further study when initial investigation warrants.

A situation in the case study can easily be repeated on feeder regulation zones by the addition of small or large PV systems in aggregate, causing reverse flow on a voltage regulator not set up for that condition. As more and more solar is integrated over the period of time, the historical peak, the daytime loads become masked and screens become more difficult to use accurately.

And hence, the need for very conservative screens. The more you want to go away from conservative screens, the more time it's going to take, and you're not going to have a quick assessment tool. DA and reconfiguration schemes must also be considered, and our utility has a goal of putting that in across the board to increase reliability.

Systems less than two megawatts can have a significant impact, as we just saw in that example, so the two megawatt threshold should remain. That concludes our comments.

MS. KERR: Thank you. Next is Jeffrey Triplett from Power System Engineering, on behalf of NRECA.

MR. TRIPLETT: Well thank you to the FERC staff and the Commission for the opportunity to speak on behalf of the National Rural Electric Cooperative Association. The question on the table today is whether or not the existing SGIP screens, and in particular the 15 percent screen, still provides a valid means to determine whether or not an interconnection should be chosen for a Fast Track process, or whether it warrants further study.

And the existing screen, if you look at the last, since the screens have been implemented, the proof of what they've been able to achieve, the screens have shown that they are sufficiently conservative, such that PV and other generation that has been interconnected with systems on an expedited Fast Track basis hasn't proven to cause harm to the system.

But it's not shown itself to be so conservative that generation interconnections can't get into the Fast Track process. Thousands, in fact, have qualified for the Fast Track process and have been done through that process.

Those that did require further study, because they didn't pass a screen, were able to be accommodated through the study process by determining what the issues to the system were and then developing solutions to those issues.

If we look at what has changed since the original screens have been created, nothing material has changed in the utility industry as far as how we design and operate the electric utility system. Nothing material has changed in the way that generation is interconnected with our systems.

What's changed is that we have a lot higher penetration of DG on the systems, and that's what's warranted the review of this screen. Review is a good thing. We should periodically review these things to determine if they're still meeting the needs that they were originally intended to meet.

But the fact of the matter is most utilities, especially the rural electric cooperatives that NRECA represents, do not have significant experience with high penetrations of DG. It just hasn't happened yet.

There certainly are places in the country that have been mentioned here, earlier in discussions, that have seen high penetrations of DG, and I'm sure that there are some utilities that have more comfort level with those penetrations.

But in general, the industry as a whole is not ready for high penetrations without certain types of screens to determine whether study is required of those high penetrations. If we look at adding supplemental screens to the process, especially those as proposed, it undermines good utility planning.

When we plan the system, we plan it to not operate at its operational limits. We have safety margins. We have certain levels of safety and reliability that we have to afford our customers. If we operate the system near its thresholds, then we're not doing our due diligence as utilities and utility planners, to ensure safety of the grid and the consumers connected with it.

If we look at the 100 percent of minimum load supplemental screen that's being proposed here, just on the surface you can see that it's right at a threshold. One of the concerns associated with interconnections is reverse power flows, as we heard another panelist speak to.

At 100 percent of minimum -- at 101 percent of minimum load, reverse power flows occur. So we're operating right at a threshold, and operating at that threshold without allowing study, to determine what impacts to the system might happen should 101 percent of minimum load be achieved, which is pretty easy on the utility system to see changes in load over time, is just not doing due diligence in the planning of the system.

If we look -- there's lots of other technical reasons why looking at the proposed supplemental screens cause concerns. I've submitted those in a written statement, so I won't go into those technical reasons just at this time.

But there are certainly better alternatives to reviewing these screens, and whether or not supplemental screens are required. As I mentioned, it is good to review this process, to determine if it's still meeting the needs. There are working groups, IEEE 1547 working groups right now that are working on similar issues.

1547.7 is reviewing the system impact study requirements, what should trigger those types of studies, routine studies and advance studies. 1547.8 is looking at high penetrations of DG and what might need to be done to accommodate those safely with utility systems.

These types of working groups with technical experts is really the perfect forum to be talking about these screens and what changes might need, and I would encourage everyone to consider letting those working groups work through their process, to determine what changes might be useful. Thank you.

MS. KERR: Thank you. Next we have Jose Carranza from San Diego Gas and Electric.

MR. CARRANZA: Good morning. I want to thank the Commission for the opportunity to participate in today's technical conference in behalf of San Diego Gas and Electric. My name is Jose Carranza and I am the Electrical Distribution Planning Manager for San Diego Gas and Electric.

I'd like to say that SDG&E has an extensive experience with connecting small-scale net energy metered solar projects in its service territory, and is a signatory to the California Public Utilities Commission Rule 21 settlement.

SDG&E believes that the current Fast Track program, including the 15 percent screen and the two megawatt limit, provides a workable and efficient means of facilitating the interconnection of small generating facilities. SDG&E's experience with the current Fast Track process does not necessarily mean that there is not room for improvement.

However, SEIA's proposal would not be an improvement in our opinion. The proposed changes to the megawatt limit and load screens do not take into account that all systems are not the same, especially the distribution systems.

The changes would likely violate the technical and operating limitations imposed by our distribution system's electrical characteristics, and thus be unworkable in many instances.

Examples of unacceptable operating conditions that must be avoided when interconnecting generation include, but are not limited to, over-voltage conditions, under-voltage conditions during transient generation, because our equipment does not respond fast enough, especially if there's regulation on circuits.

Conditions that cause those type of situations to happen are when clouds or marine layers occur, as such is the case in San Diego. Many days, there's a marine layer that comes in and lasts for the whole day.

So in regards to Rule 21, the CPUC Rule 21 distribution interconnected settlement concludes that the initial phase of the CPUC process for revisiting the interconnection rules, and is not the ultimate solution of how to improve the interconnection process in California. We still have a lot of work ahead of us.

There are two interdependent phases. Phase 1, which we're wrapping up, establishes the framework of the interconnection process. Phase 2 will address several other salient issues that remain on the table, which includes further revisions that we anticipate will be the 15 percent threshold screen. We're probably going to revisit that in the next few months.

As part of the Rule 21, we revised the supplemental, we created a supplemental review and associated technical screens. The supplemental review is triggered when an interconnection applicant proposed generating capacity causes the aggregate generation capacity on a line section, not the circuit, to exceed the 15 percent peak load.

There's been a lot of discussion about the 15 percent and 100 percent minimum load here, but what's forgotten to be mentioned is it's of every line section protected by an automatic device. That could be a fuse; that could be a recloser; that could be a circuit breaker.

So we've got to make that differentiation, that it's not just the load on the circuit. It's the load on every line section. The supplemental review looks at the level of penetration of self-generating capacity, as I mentioned, measured against 100 percent of the line section minimum load. Again, I want to stress that, because it's very important that we understand that it's the line section minimum load.

We've got to consider whether the power quality and the voltage can be maintained within the defined limits, when we allow 100 percent penetration, and whether any additional safety reliability impacts are present.

The new 100 percent of line section minimum load screen is applicable only to projects undergoing the supplemental review. So if you come in and you're above the megawatt limit, the two megawatt limit, or the 15 percent threshold, you will go into a supplemental review.

In the supplemental review, 100 percent of the line section minimum load screen is a screen that we have, but we must consider it along with other screens, which we call the power quality and voltage test screens for reliability and power quality verifications.

The Screen O and Screen P, which is the power quality and the reliability tests that we have built into the Rule 21, in 100 percent of the line section minimum loads screens are interdependent. We can't do it without each other. Without the Screen O and Screen P, the 100 percent of the line section would be problematic, as there is no way to verify that the power quality and the reliability are impacted.

It's very important for the safe operation and reliability operation of our systems that we do that. The 15 percent threshold screen continues to function well as a rule of thumb, permitting interconnections without additional study, and has been left in place in the initial review component of the Fast Track process.

The 15 percent threshold screen rule should not be replaced by 100 percent of the line section minimum load screen. As mentioned earlier, it puts us right up against the limit of our distribution system, would could cause problems if load should go away. So we've got to be very considerate of how much load is on a circuit, because it's a snapshot of today when we do the studies. Tomorrow may be different.

Speaking for SDG&E and its distribution system limitations, the current Fast Track program, including the 15 percent screen and the two megawatt limit, provides a workable and efficient means of facilitating the interconnection of small generating facilities to SDG&E's distribution system.

SEIA's proposal could potentially slow the Fast Track process for all projects, especially if the two megawatt limit is raised to ten megawatts or done away with, as is proposed. Such a removal of those limits could increase the generation size that is being proposed and thus, since it's moving away from the two megawatt limit, potentially also increase the number of projects that are failing to go through Fast Track, and impact our work flow.

Data on minimum daytime loads for periods between 10:00 a.m. and 2:00 p.m., as mentioned earlier, is not readily available for line sections of the distribution system. We don't have monitoring equipment everywhere. We don't have SCADA everywhere.

We typically install SCADA at the substation. It may be midway down the circuit, it may be at a tie at the end of the circuit. But you have many branches of circuits that do not have any type of load monitoring on them.

SEIA's proposal to use less rigorous screens and limits may not be reasonable, given our distribution limitations. The screens in the Rule 21 settlement were developed to provide the flexibility that helps address the differences in each IAU's distribution system, differences such as distribution system design, equipment, operational differences among each utility. Even in California, the three utilities have different ways of operating our system.

The differences impact the amount of penetration that can be safely and reliably interconnected onto our distribution systems. Other factors that my impact the penetration levels on the distribution system include, as I mentioned earlier, the size of the generation, the location of where the interconnection is occurring on the circuit, the amount of load on a line section, especially on minimum load days, and where we don't readily have that information available, as may have been thought previously.

The distribution system voltage also plays a big part in the amount of penetration that could be afforded in a circuit. The higher the voltage, the stiffer the circuit, potentially allowing penetration to go up. Not all of us have the same voltage on our distribution system across our systems.

Length of feeders and branches play another big role, and to make things a little more complex, not all of our circuits have the same design and capacity built into them. So I guess what I'm trying to say here is our systems are different, and interconnecting into our systems is not an easy thing. It's a complex thing that we have to study.

We believe at this time that a rulemaking is premature. We believe that potentially the Commission should continue to explore putting working groups together, to have the engineering and everybody else work together in groups, to come up with a consensus on what modifications need to be made as we move forward, to hopefully improve the penetration levels on our systems. Thank you for your time.

MS. KERR: Thank you. Next we have Michael Sheehan from Keyes, Fox and Wiedman, representing IREC.

MR. SHEEHAN: Thank you, and I wish to thank the Commission for this opportunity to -- but first, a little bit about IREC in case you're not familiar with it. We're a 501(c)(3) organization, so we do no lobbying.

But we do interconnections at the state level. We've been in 30 states in the last three years, and currently we're involved with California, Hawaii, Massachusetts, New Jersey, Washington and we're basically -- we do this on a state-by-state basis. So we're very involved at the state level.

I'd like to start off by saying that you've heard this morning that basically the 15 -- utilities feel very comfortable with the 15 percent screening. The problem is not just the 15 percent screen; the problem is what you do when you're above the 15 percent, and how do you handle that above 15 percent?

What we believe, the results that above 15 percent is that the systems are subjected to more study than is needed. This can undermine the cost effectiveness, particularly of small and residential commercial systems.

We think a different approach is needed for interconnections for those systems, and we applaud the approach -- we basically look at the supplemental review approach, as a way of getting being able to address the above 15 percent screen.

In this approach, the supplemental review has been, it's part of the SGIP. It's part of Hawaii's 14(h) and California Rule 21. We think this supplemental review process is a way of addressing the above 15 percent limit.

California and Hawaii have added a lot more detail to the supplemental review than that's in the existing FERC SGIP. In addition, we've been talking with SMUD. SMUD is the Sacramento Utility District, and they're presently using the 100 percent of minimum load.

One of the things that SMUD is doing is it's doing a calculate and measure approach. What they're doing is they're calculating what they think this minimum load should be, and then they're using a measurement device to go out there and measure kind of what's going on.

That calibration is giving them a lot more confidence that their models are actually performing the way they want it to do, because as Jose pointed out, the system is dynamic and it does change, and you need to make sure that you calibrate and you develop a risk tolerance that you feel comfortable what you have on your system is what you expect to have. So we think that's an important, another step in this process, of how to develop a better tool.

IREC endorses the proposal Rule 21, with both, with the review approach for penetrations about 15 percent of peak, up to 100 percent of minimum load. Maximum load currently is relevant to circuit criteria for interconnection process. Minimum load is currently relevant for the interconnection process.

Utilities currently look at the extent to which the generation capacity may exceed the minimum load of the interconnection process. We propose to make the consideration more transparent. Part of what we believe it needs to be the existing screen of 15 percent. Above that is not very transparent.

So what we have worked with with PG&E, SCE in California was to develop screens N, O and P, in particular to develop a lot more transparency, so that people would see what's actually going on once you get above that 15 percent.

We worked closely with them to develop those screens. In particular, Screen O goes back to kind of the Embril Sandia report. Screen O points out within 2.5 miles on a 600 amp wire, which is big wire and close to a substation, you can get a lot higher penetrations, and it gives a lot more detail for people, so that they can see what's going on in the feeder, so they'll have a better understanding as they're applying to these systems, and to get to higher levels of penetrations.

We feel one of the other benefits that this has is that there's a fee associated with the supplemental review. It's not a free step. The developer has to pay for this. It gives more information, but it's a more step-wise process, because right now you go from a Fast Track process into this study process, and you get lost in the study process because that could take long, long time typically.

So we believe that with the quick review with the supplemental review, it's a lot more useful for the developer if they can fall into that, those screens, and pass those supplemental review screens. We feel it's a lot better approach doing it. And again in Hawaii and California, we've added a lot more detail into that and to those screens.

MS. KERR: Okay, thank you. Last we have Rachel Peterson from the California Public Utility Commission.

MS. PETERSON: Thank you, and I'd also like to thank FERC's staff and Commissioners for having today's technical conference, and for the opportunity to speak about some of the reforms currently being proposed in California.

My name is Rachel Peterson. I'm the analyst who's advisory to the open rulemaking at the CPUC on distribution level interconnection protocols. Those are primarily contained in the CPUC jurisdictional Rule 21 electric tariff.

I'd also like to mention that CPUC's general counsel, Frank Lind is here as well. I can't see him. Oh yeah, Frank, and he and I really worked at a staff level to facilitate the settlement process that you've heard panelists refer to.

So what I'm going to speak from today is really two pieces of that settlement that are relevant to today's panel. But if you have, if anyone has additional questions about the settlement process, Frank and I can certainly answer those questions.

I did submit written materials. There are hard copies of those at the table at the front of the room. Then last, one more piece of context. There are a number of other signatory parties here today. I'm really pleased to see that IREC, San Diego Gas and Electric, Southern California Edison are all present in the room, and can speak very knowledgeably to what we've done in terms of proposed reforms for Rule 21.

California's at the forefront of procuring renewable energy. Starting in the middle of this past decade, we began to create procurement programs specifically designed to bring or encourage exporting generating facilities to interconnect to the utility distribution system.

Some of the best known are the renewable and combined heat and power feed-in tariffs, and the renewable auction mechanism, also known as RAM. Those programs provide a blend of avoided cost and market-based pricing, under which the generating facility sells the power either to the host utility or into the wholesale markets.

These programs are in a different place on the distributed generation spectrum, from the California solar initiative and net energy metering tariffs, which have rules specifically limiting the customer to designing their system so as to offset onsite load.

The generating facilities that participate in the feed-in tariffs and RAM are built to export some or all of their output, and they can range in size from below 500 kilowatts to 20 megawatts. California initiated these programs with a range of policy goals in mind, including reducing greenhouse gas emissions, greening the energy supply and stimulating the market for lower cost renewable energy.

Those policy goals also share a lot in common with California's interconnection policy, which has its roots in PURPA, and is intended to emphasize a clear and predictable path to interconnection for non-utility owned generation.

Now what California has done with the creation of those procurement programs is to place interconnection of exporting generators on the utility distribution systems, at a crossroads that is at times rife with conflict.

The key interconnection fact about the generating facilities participating in the feed-in tariffs and RAM is that location decisions are driven by any number of factors, some of which we've heard about already, such as remote locations, where the solar resource in California is strong; the location of an industrial facility or a dairy; or land prices low enough to accommodate a PV system of the size that's needed to make the project economics work.

As developers join in these programs file interconnection requests under Rule 21, two problems that are relevant to today's panel became apparent. First, an interconnection tariff that places all exporting generating facilities into a serial study process is only functional up to a certain point. There is a point at which the volume of interconnection requests simply becomes too much for the utility to handle.

This is the case under the presently effective Rule 21, in which if you are an exporting generating facility, you're automatically placed into supplemental review or detailed study.

The second problem is that the introduction of programs like the feed-in tariffs, that emphasize the export of power onto the distribution system, alongside the locational decisions being made by developers, such as places where aggregate generating capacity might be already high, or load levels at present might be low, places pressure on the exact screen that designates expedited interconnection as based on that relationship between aggregate generating capacity and load.

So these problems are a piece of the why, which is why California undertook a settlement process to reform Rule 21, and they also at the same time present the question of what, to try to encapsulate in a single question for today's panel.

Can the Rule 21 technical screens be expanded to identify the conditions under which an exporting generating facility can have an expedited and predictable path to interconnection? This is one of the questions that the settling parties wrestled with, and they ultimately answered it yes.

They introduced two key components to Rule 21 that are relevant to today. The first is a new penetration threshold, which other panelists have already spoken about, and the second is new exporting generator size limits for the Fast Track process.

First, as to penetration. The settling parties retained the 15 percent of peak load threshold in the initial review track of Rule 21. This is because the 15 percent screen has been keyed to expedited interconnection of over 100,000 generating facilities in California, without compromising safety or reliability.

They added a second penetration threshold to supplemental review, and I'll go ahead and read the text from the rule. It asks "Where 12 months of line section minimum load data is available, can be calculated, can be estimated from existing data, or determined from a power flow model, is the aggregate generating facility capacity on the line section less than 100 percent of minimum load for all line sections bounded by automatic sectionalizing devices upstream of the generating facility?" It's in the written materials.

This is a national first, and in California, if it is ultimately approved by the CPUC, we and the settling parties anticipate that it will permit expedited interconnection of generating facilities that would otherwise have been placed in a detailed study process.

The second major change was made by the settling parties, in order to aid in managing the number of generators applying to Fast Track in the first place. The settling parties agreed on certain size limits for exporting facilities. Those range from 1.5 megawatts to 3 megawatts in the different utility service territories.

I want to mention that the settling parties also proposed a number of transparency and predictability-related reforms, many of them drawn from the SGIP, which Rule 21 was lacking, and which they felt were essential alongside the new screening process to making the tariff actually functional.

The CPUC has not yet acted on the proposed settlement, and so these modifications are not yet part of the approved tariff, and in addition, we do anticipate that a Phase 2 of the rulemaking will open, once the CPUC acts on this first Phase 1 proposal, with potential further modifications to the tariff, focusing on cost allocation policy and technical operating standards.

If the CPUC does approve the settlement, the parties anticipate that the interconnection standards in California will catch up to today's forms of procurement, and support both procurement and interconnection policy goals, which is something that grown out of whack over the last several years.

So in that vein, I hope that the reforms proposed in California offer a model for a regulatory approach for federal interconnection standards, if the needs due to rising application levels and rising penetration levels are becoming as acute as has been California's experience. Thank you again for the opportunity to speak.

MS. KERR: Thank you, Rachel. Before we begin our discussion, I would just like to ask if you want to speak, put your table tent up so that I know that you want to speak, for both staff and panelists.

I'll start off with a question that some of you may have touched on. What are the implications, in terms of cost in time to a small generator, of going through a full study process versus the Fast Track process, either because it's larger than two megawatts or because it fails the Fast Track screens? Sure, Mr. Singh.

MR. SINGH: I'm just going to refer to SEIA's response to comments on the petition. So you asked a simple question on its face. Unfortunately, the response is very complicated. We've heard every system is different, so on and so forth. Well unfortunately, it seems like every utility process is different.

In the distribution realm, I mean obviously on transmission there's, I think, greater transparency on the transmission interconnection process across the country. What we're seeing, and this is partly due to the fact that this is a new market, and everybody's dealing with this as a new thing. So we definitely understand that.

But what we see, when you ask about cost, in the comments that SEIA provided, I'll actually refer to a SunPower statement, that for one, certain utilities are using the 15 percent criteria as a hard limit to arbitrarily control interconnection capacity on certain wholesale projects.

Once the amount of proposed solar generation exceeds 15 percent, all additional projects, be they wholesale or retail, are getting rejected by certain utilities. So I don't know what the cost is of that, if the cost is infinite or in a sense, the utilities are saying the cost is infinite.

Other utilities that have closed off certain selected circuits to interconnection have been unwilling to present their criteria, or to set up a transparent process for reviewing decisions being made to use the 15 percent screen as an absolute limit.

I'll reference, SEIA referencing Sun Edison, which said that they have four projects with a total capacity of 6.2 megawatts that failed the 15 percent screen, but then they had to go through a full two-year study process for a 6.2 megawatt suite of projects. So the cost to a developer is either excessive time, or just being told no in some of these examples.

So I wanted to emphasize that. Every utility has their own process, but we're seeing the 15 percent screen as presenting frankly unbearable hurdles for getting projects done, which is one of the reasons why we need to see a change in the overall screen.

Now if there was a clear process for a supplemental study, that was frankly concomitant with the real impacts that these projects can trigger. There might be greater comfort, but the fact is that it's triggering some of these, some hard to understand processes that take a lot of time, or we're just being told no. So --

MS. KERR: Okay. Mr. Roughan.

MR. ROUGHAN: Yeah. So in terms of the Fast Track versus the study process, there's obviously typically in most utilities some sort of impact study fee. Those fees range from a few thousand to fifty plus thousand based on, you know, how big the project is. Because you go through the estimate of what it's going to take actually to look at the particular project.

As Virinder mentioned, you know, this is new for a lot of us, in terms of getting the multiple megawatt projects. They didn't exist just two years ago, for most of us, and so we are learning as to how to do them better going forward. But ultimately, where the utility is has, I would think in most cases, if not all cases, has reliability standards they're penalized by their state regulators on.

It's very important that the utilities do take a conservative look at what they do need to do. As the utilities become more comfortable with the screens and understand more that they aren't impacting the reliability and other issues, then they will learn from that and are learning from that going forward.

I think the real issue here is just simply the massive volume of solar projects, you know, prompted by the subsidies and also prompted frankly by the base cost of the systems and panel costs have dropped dramatically in two or three years. And also what we're seeing is a lot of developers are new to this market as well. So they're just learning the processes as well.

In terms of a three, four, five megawatt project that, you know, will cost 10 to 20 to 30 million dollars to install, you know, a 20 or 30 thousand dollar study that takes somewhere, depending on the utility and the amount of volume they have, four to six months to complete, is a small price to pay on the larger system and the reliability required by the state regulators, by our customers.

I mean we just went through a very serious scenario down here just a few weeks ago, and people get very, very upset about reliability. It's the utility who pays for poor reliability.

So the need for the studies is there. Over time, I can imagine as folks get more comfortable with the screens and see that they are working, they could pursue those. But at least for our experience, we clearly detail what we're doing. We try to give as best a time estimate as we can.

Unfortunately, with the volume of projects, it does affect that. You know, what folks also need to recognize there's a dearth of experience, utility and outside consultants and contractors who understand how to deal with multiple megawatt projects on local 13 kV distribution.

We're slowly building up that talent pool again, but it just frankly didn't exist up until a few years ago. So there was a period of time as the industry has to react, to get the talent in place, to be able to do these in a quicker fashion.

You know, we talked about the seasoned folks who do utility reviews. None of those folks ever dealt with a multiple megawatt intermittent project on local distribution. They've dealt with multiple megawatt combined heat power projects; they dealt with transmission interconnections.

But the reality is this is a new animal that we're facing. It's a significant challenge that we're taking on head on, and are very interested to get these done.

We want these done as quickly as possible as well, to free our people up for other work. There's lots of other work the utilities still do every day, beyond interconnection DG, but are interested in streamlining the process over time.

MS. KERR: Okay, thank you. Mr. Carranza.

MR. CARRANZA: Thank you for your comments, Tim. I really agree with what you were saying. But I want to add a couple of things here. I think there's a dual responsibility not only on the part of the utilities, but also of developers. In California, we've taken the step to put maps of our system on a website, where developers can go and look at the capacity of particular circuits, available capacity for connecting distributed generation on our circuits.

Many times developers will submit projects that exceed the capacity of a circuit where they want to interconnect. Many times, they're interconnecting out in our rural areas, where the capacity of our circuits is either limited, or the system is weak by design, because there hasn't been very much load out there.

So my point is we need to work together. We can't make capacity available that's not available. You need to work with us in order to be able to get your studies done quicker too.

MS. KERR: Okay. Mr. Steffel.

MR. STEFFEL: A quick follow-up. When you say you post the capacity that's available, is there any simple insight into what that capacity number is based on? Is it based on the 15 percent screen, for instance?

MR. CARRANZA: We put two numbers together. We basically post the maximum rating of a particular feeder, and we also post the minimum capacity which is the 15 percent of load, peak load on that feeder.

MS. KERR: Another follow-up for Ms. Peterson. I understand through Rule 21 there will be an additional report that will be available to developers. Will that have more information than the maps currently have?

MS. PETERSON: Yes. You're referring to something called the pre-application report. So it's a new report that the settling parties proposed. It is intended to work similar to what Mr. Carranza was just referring to. You can pay $300 and get a first look from the utility about your proposed point of interconnection.

It is limited to data that already exists, say technical data about the distribution system where you're looking to locate, as well as existing peak load levels. Any data that they do not have to calculate or measure or conduct some form of analysis for. But it would provide more information than the interconnection capacity maps, yes.

MS. KERR: And it sounds like it's fairly localized for a specific area?

MS. PETERSON: It's driven by -- your report is what you request for your point of interconnection. If you look at the maps, you begin to see broader areas, surrounding substations, particular electrical areas where the three investor-owned utilities in California have identified capacity levels.

MS. KERR: Okay. Mr. Steffel.

MR. STEFFEL: Although we can't comment for other utilities, our utility actually does a static load flow screen, to determine whether something would need to go on for study. So sometimes we can approve connections of systems that would fail the FERC screens, based on our internal study.

Right now, we use a third party vendor to do the studies. It's usually between 20 and 30 thousand. Depends how complex it is. Takes generally up to eight weeks. Sometimes it is a little more, sometimes a little less.

I think one of the challenges, just like Tim had mentioned, is we found that third party vendors even had to be coached on making sure they got things right, and so the talent and the skills are really being developed for doing the studies correctly.

If you get the study wrong, you're going to have a problem on your hands, possibly for a long period of time. And, you know, it only takes one system to go in to cause problems for a long period of time for a lot of customers.

So that is a significant factor.

But we do, anything we can do internally we do, and we don't send anything out. We do that for free for all the developers. That is within generally just a few days, within that 15-day period. So very few of them percent-wise go out for the detailed study.

MS. KERR: So some folks have already addressed this, but just to make sure we have a clear picture of it. We're interested in whether there are regions or locations where it's difficult for small generators to take advantage of the Fast Track process due to the 15 percent screen. We've mentioned, some of you have mentioned states, but we're also interested in different parts of utility systems. If anyone can address that.

MR. ROUGHAN: As I mentioned, you know, many, most, I should say, of the projects we're currently seeing developed in Mass and Rhode Island, are on the fringes of our electric distribution system, because that's where the land is available, that's where it's, you know, economically feasible for the developer to pursue the projects.

And you know, when you're on the tail end of the system, A, there's not a lot of load that's required, that was required to be served. So now you have to upgrade the whole system. You know, a lot of places you've got single phase or three phase extensions that have to be built.

You've got different substation modifications or recloser modifications on those circuits, systems that simply don't play well with a simple screen.

You really do need to do the analysis as to how that's going to interact, because in many of those locations, on a beautiful late May afternoon with max solar output and minimum load in the area, you've going to have export up to the transmission system through the local substation.

We're seeing more and more of that as time goes on, and again, it can be dealt with. We study them. We interconnect these projects. They go online, but there is that needed piece that has to be done, of the study and typically extensive construction. But then we can get these projects online.

There's really no reason a project can't be interconnected. It's just simply sometimes takes time and money, and ultimately, things like having maps or pre-application reports that lots of us do will guide that developer. One of the really curious things we've seen since the state subsidies went into effect in New England is that up until a couple of years, virtually anyone who was going to interconnect to the utility called us prior to sending in the application, and wanted to know what the issue was, an initial kind of discussion.

Since the changes in the subsidies, that vary in nature, these projects are just coming in. For a while, they were coming in a clip of five to 20 megawatts a week to our interconnection folks in Massachusetts. Well, you didn't even know that they were -- they hadn't called us. They hadn't asked for anything to look at first. They were just coming in the door.

Then when we did review them, we said "oh lookit, we've got some issues here and what-not." We have developers fighting for the same parts of land in certain cities and towns. That's always a challenge, who owns the property, who's got the rights to do it.

So there's a lot to this, and I think as both the developer and the utility communities mature as to how to deal with these, I think we'll be over this issue that temporarily -- that I believe is simply a temporary issue that we'll be able to work our way through.

MS. KERR: Mr. Lennox.

MR. LENOX: Yeah. I wanted to comment that it's important to just keep in mind that what we're talking about here is that the 15 percent screen is often being used as a ceiling, as opposed to being used as a floor, and that significant reform in the Rule 21 settlement is a use of that screen as a Fast Track floor in essence, and then defining a set of screens that give a lot more -- give a lot more structure to what happens to a project that does not pass that 15 percent of peak load screen, and provides a method of getting projects online that's defined, as opposed to status quo, which is undefined.

That's really what we're talking about here. So when we talk about what the cost is, the cost is going from a defined process to an undefined, open-ended, in terms of cost and time frame, process. That's the pain.

MS. KERR: Okay, thank you. Mr. Carranza.

MR. CARRANZA: I think we've got to be careful with the 15 percent screen and making it the floor, because there are many circuits that potentially can't even accept 15 percent penetration, and making it the floor may impact reliability in the operation of a particular situation.

MS. KERR: Ms. Peterson.

MS. PETERSON: Yeah. So you asked whether there are regions or locations where it's difficult for developers to take advantage of the 15 percent screen, and I think both of the prior folks who just spoke are both right. The 15 percent screen is one of a number of questions that are asked during the Fast Track process.

A number of others deal with other technical issues, such as short circuit current contribution, short circuit interrupting capability, the line configuration.

So whether the 15 percent screen alone is barring an applicant from interconnecting at a particular site may not be always the complete answer. There might be, as the utility works through the Fast Track questions, other technical issues that prevent it from coming online.

So although this panel is focused on the 15 percent screen and the new potential backup to it, there are technical issues at the same time. Right alongside that is the question of writing out, is the matter of writing out specifically what those questions are.

I'm using our Rule 21 new proposed framework as a cheat sheet here. But the point is for transparency and predictability, as Mr. Lenox just said, the point is to write the questions down, so that developers know exactly what's being asked and what the technical issues are that could send their project from initial review to supplemental review, and then potentially from supplemental review into detailed study.

MS. KERR: Mr. Carranza.

MR. CARRANZA: Yeah. I just want to take Rachel's point and clarify or add that in addition to the penetration screen that's put in place, we also have got to be considerate of the reliability and power quality screens that look at the 100 percent penetration issue on a line section.

So we've got to be considerate of that when we're considering, you know, exceeding the 15 percent limit or the two megawatt limit.

MS. KERR: So just to follow up, you had said earlier that there are some locations that can't even go up to 15 percent.

MR. CARRANZA: Uh-huh.

MS. KERR: Are those, are there technical issues that you're referring to?

(Laughter.)

MR. CARRANZA: Location of the interconnection is very critical. If you are interconnecting close to a substation, where we have plenty of capacity, many times it's not an issue. If you are connecting your project 15 miles out, away from the substation, where we have small wire, the size becomes really critical of your interconnection project.

If it's 100 kW, we may be able to accept it. If it's one megawatt, I can tell you it's going to be difficult.

MS. KERR: Okay, thank you. Mr. Triplett.

MR. TRIPLETT: Thank you. I'd like to thank Ms. Peterson for her comments, because we're talking about the one screen here, the 15 percent penetration screen.

But in reality, we really ought to be looking at all the screens, because it's not just the 15 percent screen that triggers these studies. I'll speak from a little different perspective representing the Rural Electric Cooperatives. All of our systems are rural.

Very long lines, smaller wire, higher impedance systems, by design to just service the load that's required. So the 15 percent screen for a rural electric cooperative is not the only screen that gets triggered very regularly.

So there are, as has been mentioned by several other utilities here, a number of technical issues that come about with these smaller systems, that are very rural long lines that have to be addressed. So we really need to be thinking about the whole process, not just one screen.

MS. KERR: Mr. Coddington.

MR. CODDINGTON: Thank you. I just wanted to address a number of the comments that have been made over the last few minutes regarding some of the examples of circuits where even penetration levels lower than 15 percent present trouble. I agree, that that's certainly a possibility.

I think that actually highlights one of the reasons why using actual, minimum daytime load data is more beneficial than estimating it based on 15 percent of peak data. I mean I think that actually spells out a really good reason if the data is available, if that information can be measured or estimated, but that is a more useful number.

And certainly there are issues with location which create other constraints. Some of the more rural circuits are certainly good examples of where trouble may lie. But again, if you use 15 percent of the minimum daytime load of a line section, some of these problems, I would hope, would be mitigated before they come about.

Because the utilities are right. They're the ones responsible when troubles come down the road, and we do need to maintain a safe, reliable and cost-effective electric system, and that's clearly the lifeblood of our economy. So we want to maintain that.

Again, I'd just reiterate that using actual minimum daytime load data seems like a better way to sharpen our pencil, and rather than estimating this, because effectively 15 percent is just estimating a portion of what minimum daytime load is. Thank you.

MS. KERR: Arnie?

MR. QUINN: Just to follow up on that. So I think we heard that, from Mr. Carranza, that potentially the 15 percent screen doesn't work for all situations, and you've, Mr. Coddington, indicated that potentially that's because of the screen being based on something other than actual minimum load data.

Is that, do people agree that that's the primary issue, or are there other parts of the Fast Track process, other parts of the screen process that are also not kind of working well, that would lead to 15 percent being the wrong number for some feeders?

Maybe I'll put it a different way. If something gets through the 15 percent screen, why isn't it failing one of the other Fast Track screens, to identify that that area or that location isn't a good Fast Track location?

MR. CODDINGTON: If I could make one comment, and I think that's a great question. What I think we've heard are several anecdotal cases of where the 15 percent screen failed, and as one example, I think Mr. Steffel mentioned that they had, they used the 15 percent, and they actually had reverse power flow anyway, and that they had high voltage, which resulted in customer equipment being damaged, which is certainly a concern for all utilities.

I think again in these anecdotal examples that were given, had the utility looked at that minimum daytime load, at least in these examples, that may have actually failed that screen, and gone on for supplemental review, and that system may not have been allowed, or they may have been mitigating measures, like reverse, you know, bidirectional voltage regulation, which is available, might have been deployed.

But in the case of just using this 15 percent screen, at least in the examples we've heard, the utility had some problems. So I guess I would just submit that there are examples where the 15 percent screen doesn't really do the job that it needs to, but in most cases, it's probably catching systems that need to go on for supplemental review.

MS. KERR: Okay. Mr. Carranza and then Mr. Sheehan.

MR. CARRANZA: Just let me add, again, that the 100 percent minimum load of line section is not available all the time. So we fall back to the 15 percent rule. So that may have been the situation here that we're discussing.

In addition, there are other ways to get into the supplemental review. NEM also can go down in that direction, which came past all the rules eventually, and get into supplemental. But let me add one more thing.

As I mentioned in my opening statements, we may have load today in a particular section. But over time, load may change. A particular customer may shut down their business and load disappears. The 15 percent may allow generation to be attached at the time that it was studied. But when that load disappears, now you get backflow and potential issues. So that's something you've got to really be aware of.

MR. SHEEHAN: Just a point of reference. I did a report for solar ABC's, reviewing the FERC SGIP screens with the IEEE members, 1547.6 and .8. We reviewed all the screens for which ones were problematic and which ones were of concern.

And traditionally, the 15 percent is considered to be the one that's most, that trips up the most. The other one is a line configuration one. There's a lot of issues related to subtransmission, which we have not really talked about this panel.

But I think that's a discussion, ripe for this discussion, especially the way Southern California runs its system and the subtransmission, the way it's networked versus the way it could be a radial subtransmission.

So there's other issues that are on the table, that sort of need to be looked at, that are beyond this 15 percent screen. So if you -- we think it's open for a bigger discussion. But this discussion this morning was just on the 15 percent screen, and I want to make sure that everybody understands there are a lot of other screens or need to update that.

The original 2005 order suggested every two years that this be revisited, and this has not been revisited since the 2005 order. So I think it's important to recognize other screens do trip up, but the one that's the most sort of common is the 15 percent.

MS. KERR: Tom.

MR. DAUTEL: In cases where load changes, is there someone who can help me understand what happens after that happens? Is additional equipment put in? Is the interconnection impacted or what's the scenario?

MS. KERR: Mr. Carranza.

MR. CARRANZA: Potentially, the utilities have to fix the problem. We may need to reconductor, we may need to employs several different strategies to fix the problem.

MS. KERR: And I assume the problem would be the same, whether you've used a 15 percent screen or 100 percent minimum screen?

MR. CARRANZA: That's right.

MS. KERR: Okay.

MR. DAUTEL: And real quick, do you usually know about it ahead of time, because there's a load that's dropped of that you're aware of, or is it more kind of you notice the effects of it?

MR. CARRANZA: It depends, it depends. Sometimes we're aware of it and sometimes we become aware of it, because our customers begin complaining of potential issues, or issues that they're seeing with reliability.

MS. KERR: Okay. Mr. Coddington, I think you've had yours up the longest.

MR. CODDINGTON: Thank you. I've got just a couple of comments, and I think one addressed yours, Tom, and my own experience of 20 years in the utility business, in that load data is historical. So you look at load data and there is no guarantee that that is what a feeder or a line section is going to do.

As a matter of fact, you're pretty much guaranteed it's going to be different than that historical profile. I think the utilities use it. It's the best tool you can to estimate what the future may be.

But it's an excellent question, and it's a concern that I share with the utilities here, that if load goes away and that presents a problem, that is on the utility's shoulders.

But I would say I just wanted to address another comment. This comes up pretty regularly. But there was a comment that the load data on a line section for minimum load is not available, or it's just load data on a line section, period, is not available.

So my question is well then how do you come up with a 15 percent of that line section? I mean there are ways to estimate it. There are ways to measure it. I'm saying there are ways to do it, but the comment came up that that load data at a line section is not available.

Clearly, it must be available, at least to determine what that peak number is, so that you can take 15 percent of peak. So I would just challenge that assertion, that the data's not available or somehow, there's no way to estimate that.

MS. KERR: Yeah. Along those lines, I had a follow-up question for Mr. Sheehan. You had mentioned that SMUD is doing something that sounded different, I guess, than what other utilities are doing, the measurement of minimum load.

MR. SHEEHAN: I wouldn't say it's different, in a sense. But I'm saying they've already gone to the 100 percent of minimum load threshold already. So not very many utilities have gone that direction yet. So they're already at that level.

But one of their practices that they do is to put out a meter on the line, to measure kind of the affected area that they think is going to happen, and they download that data and estimate what they think should have been the load, based on their calculations.

So they do a calibration between the estimated and as Michael Coddington pointed out, the real load that's going on on the system. So they're measuring those two to see how close they are, and get more confidence and more sense of the lower their risk level and threat to going backfeeding or having a problem.

Again, I think this issue of backfeeding is really the loss of voltage control is what the utilities are concerned about.

MS. KERR: Okay. If the other three folks who have their name tags up could real quickly address this, and then we'll move on. Mr. Roughan.

MR. ROUGHAN: Uh yeah. I wasn't going to talk to that.

COURT REPORTER: Your microphone.

MR. ROUGHAN: Oh, I'm sorry. It was more of the fact that, you know, once you've agreed to a minimum load, you've completely lost all your flexibility for rearrangement of the circuits. You know, even though many states have goals to reduce load growth to zero through efficiency programs and everything else, the reality is everyone likes their gadgets. Load continues to grow.

So when you go to put a new substation in, typically what you're doing is you're offloading different circuits around, because now you have new source to serve the load.

So once you're stuck with a minimum load number, you're stuck. You can't rearrange it anymore. You now don't have the flexibility on your system, both during planned upgrades, which is a new substation, and during unplanned storms and reliability considerations.

I mean as mentioned by Jeff prior, we strive to only load our systems to 50 to 60 percent of the circuit rating, so that we can move loads around during outage conditions, so we get as many people back as possible.

So when you now set up that on that circuit, you need X megawatts of minimum load because you've allowed so much solar on it, you're stuck with it going forward.

That's the concern about the future flexibility, and frankly the cost of the distribution system, because once you're stuck, as Jose mentioned, you've got to reconduct, you've got to do this, you've got to do that. Because once the system's online, you have very limited ability to require, and in many cases no ability to require that end use customer, developer or solar farm owner, to pay for any changes or upgrades at that point.

Because they're online, they've signed an agreement with you. You've agreed that they can run the way they are. So going back asking them for additional funds to do something different is just not -- just doesn't occur.

MS. KERR: Would having additional DG, distributed generation on a line in some ways give you flexibility?

MR. ROUGHAN: Well, there's two problems with -- well, you know, also in many cases, unless it's a multiple megawatt project, we have records on our GIS of all the generation and nameplate ratings. But what we don't have any transparency to is how much of the DG was actually operating during that peak hour that we saw either the peak load or the minimum load.

So we have no -- all's we're seeing at that breaker or substation or recloser online is the net power flow through that device. We have no idea, unless we have larger projects where we have to have control and equipment to understand what it's doing, because it's so large.

We may know that nameplate rating is 1-1/2 megawatts on that circuit, besides the three megawatts of large projects. But we have no concept, from a transparency perspective, how much of the 1-1/2 megawatts is actually still operating.

We can see what the big project is doing at our peak or minimum, but we don't have any transparency into what those individual units are.

I mean as we all move into the advanced meters and Smart Grid and all the rest, we will get that transparency. But most of us simply don't have that today to understand that. So that's the other difficulty of using simply a peak load or a minimum load value, is that you don't -- it's a net power number. It's not -- it's the load on the circuit less any generation that's actually running at that particular hour.

MS. KERR: Thank you. Is to a good time for you to follow-up? Okay. Mr. Steffel.

MR. STEFFEL: Okay. I'll try to move through quickly.

COURT REPORTER: Microphone.

MR. STEFFEL: Oh. You asked a question about where could the 15 percent screen fail. I think we've given an example, plus mentioned other types of circuits with load profile anomalies. Now that's the very, you know, that's rare, but it does occur.

One of the issues is protective zones versus voltage regulation zones, and at the beginning of the voltage regulation zone, you're going to have a voltage regulator. Not all of them are reversible; some of them are older and we'd have to change if you're going to have reverse flow.

Number two, even if they are reversible, if they're not set correctly, they can also operate incorrectly. So you can have something meet the 15 percent criteria for a protection zone, but not a voltage regulation zone.

If you look in the material, you know, we gave you, there is four voltage regulation zones on the rural feeder that I mentioned had a 3.3 percent minimum hosting capacity. So what did we do in that case, where we had that problem? We had to reconfigure the circuit and the substation.

So just like Tim mention, that does limit our ability to reconfigure again. We've now reconfigured to handle that problem.

Another impact is on distribution automation, and this is where we're developing automatic sectionalizing and restoration schemes across the board.

We have some circuits that have three megawatts of PV, and what happens when you have a fault? PV disappears. That was three megawatts, and our system thought that the load was three megawatts less on an automatic scheme.

But then when it picks up the load, there's three more megawatts, and then five minutes later, there's three less megawatts. So the voltage regulation and everything changes. We've actually had to block some schemes. So does it impact reliability? Yes. I mean that's a clear indication.

On load data, new systems that went in since the reading that you had of your load measurement, whether it's minimum or peak or whatever, effect it. The contribution that the systems, that were on the system, and Tim mentioned that to the load reading.

I mean it could be that you had a cloudy day, the day of your minimum load or peak load or whatever, or it might have been a clear day, and then maybe the systems are deteriorating or not online. Then you've got pending systems that you've got to also account for, even if you do look at these load measurements that you have.

Then there has to be a buffer for inaccuracies. You've got load imbalance, you've got phase imbalances and other types of things that are going to trigger things on the circuit. So you can't just go up to 100 percent minimum load and think that's a great screen. There has to be a buffer, or else you're going to still end up with a lot of problems.

MS. KERR: Okay. That's a good segue to our next question. So we've heard from SEIA and other commenters that the 15 percent screen's a problem. We've heard from some of the panelists today that 100 percent minimum load screen may be a problem.

Are there other things we should look at? If there are problems with both of those, are there alternatives that we should consider, to keeping people, generators in the Fast Track process? Oh, Mr. Triplett.

MR. TRIPLETT: Well, I think that's a great question, and that's ultimately the question of the day. I think that there are things that should be considered, and as I mentioned earlier, there are working groups that are considering these things right now, the 1547 working groups.

Those working groups are comprised not only of representatives from the utility industry, but also representatives from the manufacturers of equipment that are interconnecting with distribution systems, and the developers and the generation interconnectors themselves.

I think that's really the appropriate forum where these things should be discussed, from a technical nature. How effective are the existing screens, and what can be done to make them more effective?

At the end of the day, most generation interconnection requests can be accommodated. It's just a matter of does a study need to be done? Does there need to be any mitigation techniques to accommodate that, or can it just be done, reasonably assured that there will be no safety and reliability concerns to a Fast Track process.

So I think those working groups, in my opinion, the stakeholders should consider allowing that process to go through and answer those questions exactly.

MS. KERR: Thank you. Ms. Peterson.

MS. PETERSON: Having been through eight months of settlement discussions about the screen and a number of other issues, I guess I would --

I would tout the 100 percent of minimum load backup screen within supplemental review, with the attendant means of calculating, measuring, determining, etcetera, as really one of the best steps forward that can be taken at present, before you get to the much more indepth technical advances that I believe are coming, and as Mr. Triplett said, are coming from places like the IEEE 1547 working group.

If an advance is being pursued in terms of expanding Fast Track, and remaining within a certain zone of safety and reliability, then I think that these screens, although they, as everyone notes, they do have their flaws, are the best present-day step forward. Other long term approaches are exactly that; they're longer-term.

MS. KERR: Thank you. Mr. Sheehan.

MR. SHEEHAN: Just to capture that in another way, we believe that above the 15 percent is really one of the key issues we want to address, and the supplemental review, which is already in the FERC 2005 Order, and it's in Hawaii Rule 14(h) and California Rule 21, that's really the venue we think is the best, a great approach to sort of get to the next level, without going through a detailed study and getting into a lot more.

It's again, using utilities basically N, O and P in Rule 21, the penetration screen, the power and quality, reliability and voltage fluctuation, the safety and reliability issues, those issues need to be addressed.

Doing it in the supplemental fast process really addresses, we think, the key issue, that for those projects that you can get through a lot faster, instead of going through a full study process and getting caught in that full study process.

Because that's the time and in a lot of cases, that's really where the hang up is. We can get a lot more of those projects that are closer in, that everybody agrees can go a lot faster, and doesn't need that full monte study.

MS. KERR: Mr. Steffel.

MR. STEFFEL: PEPCO Holdings, Inc. is taking another approach to this, and what we're working on is acquiring a semi-automated study tool that will operate in a time series load flow, and can operate quick enough to respond within the 15 days, so we can actually do this study in-house.

We're moving ahead with it. I mean it promises to be fast. All the testing we've done indicates that. Right now, we currently for any system that's over 250 kW, we do a static load flow anyways. So this would just be an extension to actually doing a time series that looks throughout the whole year, and actually pulls in the solar data.

It actually will be a little less conservative to allow larger systems. It would give back a much more detailed feedback to us, and actually give us the true impact on our system. The tool would also continue to look at aggregated type of impacts up and down the T&T system.

So it would also incorporate pending, and it would incorporate things that have gone in. So it eliminates some of the problems we've mentioned with load measurements, and trying to adjust them for things that have come on the system, things that are pending and so on.

MR. QUINN: Can I just ask a follow up on the -- it seems that there might be a consensus, that everyone agrees that some sort of supplemental study should be allowed.

There should be some option for the interconnection customer to do some sort of supplemental review if they failed the Fast Track screens, but would prevent them from having to go through a, you know, full-blown long, costly study. Is that consensus there? Does everyone agree with that general principle or statement?

MS. KERR: Mr. Singh.

MR. SINGH: Yes. I guess --

COURT REPORTER: Your mic.

MR. SINGH: Sorry. We just don't know what that supplemental study looks like utility by utility also. So I don't want to complicate the question, because you asked what seems like a simple question. It's the Wild West out there in a sense, and again we're all dealing with the new market and such.

But we do not see consistency across utilities and how they're treating DG. We do not see consistency in standards. We do not see consistency in processes. We do not see consistency in what it actually costs. We do not see consistency in what we're being asked to do.

I understand the leaning towards extreme conservatism among utility distribution and transmission engineers. You don't get a bonus, in a sense, by handling more DG. You just get fired if there's a reliability event. I understand that. I used to work for a utility.

But we have states, New Jersey just passed legislation that is accelerating its solar mandate. States want to do solar and there's annual requirements.

Study sounds nice, but we're going to wait two years to come up with revisiting the standard through IEEE, and then we're going to spend a couple more years with more study on projects, and states are saying we want solar right now.

There's a real disconnect between the immediacy of the issue there, based upon what states and their legislatures and governors have decided what is important, versus some of the tones of discussion here about let's keep on studying this.

We might be a little more comfortable with some of that tendency if we understood what the study process was, and all of those other issues that I raised. But that's not what we're seeing here. So sorry for a little bit of the opining there also, but you asked a simple question.

We don't know what that study process looks like utility by utility. So that creates a huge problem.

MS. KERR: Mr. Roughan.

MR. ROUGHAN: I think we continue to concentrate on what the utility can and what the utility cannot do, and I think there is significant responsibility from the solar community to also help us understand what they can and can't do. The dilemma we have here is the intermittency of the projects.

On an hour by hour, minute by minute issue with cloud cover, on a month by month level, just because of the radiation changes over the course of the year. So we're being asked to answer a question that doesn't have a simple answer, and we're being asked to do it through screens and do it quickly and get these online fast.

What I fail to see is the need for a two-way street here, to have the solar community be able to provide to the utility some sort of certainty as to what their project can and cannot do. It's all that the utility needs to do this because of all these good reasons, but there are just virtually no quid pro quos from the solar community.

For example, if a customer really wants to go through the Fast Track process, really doesn't want to deal with detailed review, there's a relatively simple way at that. There's a relatively simple way if they manage the input of the solar project to certain levels at certain times of the year, and we have some control over that, over the management of the output and the solar array, to make sure it doesn't impact our system.

Then they can live within what they're doing. There may be certain hours of the year where they have to be cut back, perhaps in terms of output. But again, really what's not happening is any work to try to manage the intermittency of this resource. If there was additional work there, and I think that's what Jeff really talks to this, in terms of what the IEEE working group will and can do.

By bringing up ideas in those types of groups, they can be vetted and fleshed out as to what works and what doesn't work. But simply controlling the output of the solar project for certain hours of the year may well make these things easier to manage on the utility distribution system.

Putting some responsibility, instead of just simply having -- the utilities have to absorb whatever they do whenever they do it.

MS. KERR: I'm curious as to what you're seeing, Mr. Lenox, if you have a reaction to that, and then I'm also curious if there is equipment that would make that relatively easy to do?

MR. LENOX: So my reaction to that is that, you know, those, I think are options if you're failing screens, and there's both technical and economic implications to those measures, those measures that exist. But we don't want -- and they're evolving over time as technology advances.

But I think we do need to keep in mind we are talking about making changes in a relatively short term to accommodate the very fast growth of the industry, versus the longer term process that is being driven, the 1547 process at some more venues. But that is, you know, it's really too far out to address the issue we're trying to address here.

We do need to have a process so that we can study these projects in an appropriately expedited fashion, so we can get technically viable projects online. That's the bottom line. We're not talking about putting projects online that are going to significantly impact the reliability or safety.

That's not what we're trying to do. We're not trying to degrade the reliability of the utility system. We have a model here that we are looking at, that accomplishes that. So the question really isn't is there a bunch of things that the PV industry can do to mitigate this, that or the other impact.

The question is, is there a way for us to decide that a project is not going to have an impact, in a manner that is consistent with the reliability, but also consistent with policy goals and with commercial realities. If we get outside of that space, then we can start to talk about well, here we have, here's a project we want to do.

It's failed this screen or that screen. What are the mitigations we can put in place and the solar industry, I think, in general is very open to having that discussion and we do have that discussion on a project-by-project basis.

MS. KERR: Thank you. Mr. Sheehan.

MR. SHEEHAN: I would like to avoid the discussion, but since it's been brought up, I think energy storage is off topic, as far as I'm concerned, for this discussion here. It clearly is not something that we've been asked to talk about, because it's beyond --

We've really been focused on the time and the amount of money it costs to do interconnections of greater than 15 percent. If we get into the issue of storage, that's well beyond kind of where we want to be at this today. I just want to take that off the table.

MS. KERR: Mr. Roughan.

MR. ROUGHAN: Yeah, and I guess I'm not -- (a), yes equipment is available to -- I mean they've got this inverter control software that can easily be throttled back up and down as much, whatever you want to do. That's very simple to do.

So the reality that that can occur, I'm just suggesting that that be part of the discussion as well, instead of simply what is the utility's requirements and what can they do and what can they not do. Where the bulk of these projects are interconnected is under the jurisdiction of the state regulatory bodies, who give the approval for the distribution utilities for their recovery and for their capital plans every year.

We're talking about significantly potentially impacting those agreements that are either in place or have been talked about. I mean the planning process for a utility, we have projects that are planned out three, five, ten years out that are in-process and being approved now and pulling together resources for.

You know, juggling that and changing that around because of solar projects could make that much more inefficient. But it's just another idea here that is, I think, worthy of a discussion, because ultimately to take advantage of the fast solar growth, that can and will potentially put reliability at risk, simply by a rule that says if it passes this, you have to do X, Y and Z, and you don't have authority to do anything more, I think does risk reliability in the short term.

By managing the process and studying it the way it needs to be done, we can come up with a much better process for utilities and for solar developers and for society as a whole.

MS. KERR: Mr. Coddington.

MR. CODDINGTON: First, I just want to say that I think Mr. Roughan brings up an excellent question, although I think it's really off topic for this question surrounding screens and 50 percent. But if since the question was raised, if I could give my own perspective on a couple of these topics.

I think the solar industry and especially the inverter industry, and along with standards groups and national labs that have been mentioned today, are working on many solutions to make these systems more grid-friendly, to be better utility partners, to behave themselves in a more traditional way, to act more like utility generation that has been online for, you know, over 100 years.

So I think that we're moving that way, and some of the standards efforts, especially the IEEE 1547 groups, are working to find ways to deploy some of these advanced functions that I think really will make our future look much better in this whole discussion area.

I did want to just touch on IEEE 1547. It's been mentioned a few times, and I'm not really sure that that group is going to address screens to anyone's satisfaction for this discussion this morning. But I do believe that the 1547.8 working group will address ways to deploy some of these advanced functions, to again address Mr. Roughan's reasonable concerns. Thank you.

MS. KERR: Thanh?

MR. LUONG: I guess I had a question regarding the IEEE working group. How far does it come out with a resolution?

MR. CODDINGTON: So if I could, since I was secretary of IEEE 1547.6 for Secondary Networks, a little off from some of the other working groups. We actually have a chairman of one of the current working groups in the room today, Mr. Saint with NRECA, working on 1547.7, which is the supplemental study group.

There's another active standard being developed, and it's 1547.8, which I think is what most of the references have been aimed at today. That's really an advanced, you know, really a focus on higher penetration, some of the new advanced functions that are being, that are available today.

But how do we deploy these? How do we act put them into use? To answer your question, I think that over roughly the next year, that would just be -- no one really knows when a standard is going to be completed and available. But it looks like, you know, within the next year, that 1574.8 should go to ballot, and then hopefully within a few months after that it may be voted in as a standard.

The standard for interconnection, adopted by FERC and many states, 1547, that's the interconnection standard, was approved just a few years ago, 2008. But you know, there is discussion now about revisiting the interconnection standard, and looking at ways to perhaps integrate low voltage ride-through, low frequency ride-through.

Those functions are being discussed, as well as volt bar control, some of the things that again may make this technology more utility-friendly, and to be able to mitigate perhaps some of these variability concerns that the utilities have raised today. I hope I answered your question.

MS. KERR: Okay. We're actually sort of running out of time. I'm going to move along a bit. So assuming there should be additional review screens in the Fast Track process, should these additional review screens be different based on the operating characteristics of the different types of generators, and what types of generators should have different screens? Mr. Coddington.

MR. CODDINGTON: If I could just make a short statement. Yes, I do believe that any kind of technology with power electronic inverters on the front end should be treated differently. The engineers in the room know that traditional generator synchronous machines have greatly different characteristics.

They're of, I would say, greater concern for interconnecting onto the distribution system, whereas inverter-based systems generally behave themselves in a much more predictable way, and are inherently safer in nature.

MS. KERR: Ms. Peterson.

MS. PETERSON: Yeah. I'll just answer by identifying some of the policy guiding Rule 21 in California. The California Public Utilities Commission has long said that the interconnection tariff, Rule 21, shall be technology-neutral, and that was the guiding principle that the settling parties stayed within in developing the reforms to Rule 21.

So as a result, the screens in the Fast Track process identify the potential different technical issues that different types of generators might trigger. So a synchronous generator might trigger a different screen from an inverter-based generator.

The one place where the settling parties proposed a slight difference is in the measurement of minimum load for solar PV in that one screen for 100 percent of minimum load. The solar PV measurement of minimum load is based on daytime hours, and for all other forms of generating technology, it's absolute minimum load.

MS. KERR: Mr. Triplett.

MR. TRIPLETT: You bring up a good point. Certainly, different types of generation have different impacts on the system. But I think ultimately, it's not the type of generation but the impact seen. So I think the technical screens should still be broad in nature, looking at things like fault current and impacts on voltage regulation, rather than specifically saying inverter-based, induction, synchronous, so on and so forth machines would have these separate rules.

So I think the rules need to be global, because ultimately it's the impact on the system. We don't care if it's an induction machine or an inverter-based machine or a synchronous machine causing voltage concerns on the system. We just care that we have voltage concerns on the system.

So the screens should still be based upon the root concern, not the generation type.

MS. KERR: So if again, assume that a minimum load screen would be effective as an additional review screen, and by effective, I guess I mean that it would decrease interconnection costs for distributed generation without compromising safety and reliability.

How would such a load -- how would such a screen be structured? For example, is 100 percent the appropriate minimum? In the California process, were other percentages discussed? Are there other issues based around that percentage that we should know about?

MS. BRYANT: Specifically earlier, Mr. Steffel said --

COURT REPORTER: Microphone, please.

MS. BRYANT: It's on. Is it on? Okay. Mr. Steffel said earlier that you thought the 100 percent minimum daytime screen was perhaps not good enough, because there wasn't a built-in buffer. So if that number was reached, then what would happen at that point, and what reliability implications would we incur, I guess, if we let the 100 percent go through.

So I guess in addition to the rest of the panelists, specifically for you, is there a number that's around 100 percent that you would be comfortable with, or what sort of buffer numerically or otherwise do you think is necessary?

MR. STEFFEL: Well, the buffer would need to take into account the inaccuracies of your estimation. It would need to take into account the possibilities of load change and load profile change. We talked about, you know, the possibility of industries not working on the weekend, where they had been running seven days a week.

It needs to take into account on balance on system, which can change. So one of your phases, if it's going to get the reverse flow on it, may be the minimum load of that. You've got to make sure you've got the minimum load phase, not just your average.

You've got the operation of the existing PVs in that section that you've got to account for, and the variation from year to year, and then you've got -- you've got to take into account what the pending ones' impact will be.

So the thing, and many utilities aren't collecting that data right now. So if we do have it available, we put it, move it down from a whole feeder down to a section. You've got to take in all those accounts, and all I'm saying is you need a buffer.

You can't just go right up to 100 percent minimum load, and allow something to go through where you haven'+t checked a voltage regulation devices to see if they're going to have problems in reverse flow and other types of things. So that's a problem.

Then when you have a single feeder on a

distribution transformer at a substation, protection folks would want transfer trip on a system that could actually backfeed into the transmission system.

So there's a number of things that have to be looked at, and if you go right up to 100 percent of your minimum load, daytime load, you're just not allowing yourself a buffer.

One of the other things I was going to mention before is we have almost no control, monitoring or control, over most of the systems out there. If they're on, we have to send someone out there if there's a problem to turn them off. Yes, the very largest ones we do have monitoring and remote possibility of disconnect.

But you know, the vast majority of them are going to operate until someone actually goes out there. A lot of times, the places are closed. Nobody's there. They're operating totally on their own.

So you know, if we push everything right to its limit without any control, and just to give you an example, the IEEE 1547 recommended that there be monitoring control at 250 kW and above.

Well, at the state levels, we've been restricted. We can't put anything over, anything that's two megawatts and below can't have monitoring controls. So you've got a tremendous amount of the solar out there has no control from any central point. So you have to consider all that when you make these screens and go right up to certain limits.

MS. KERR: Mr. Coddington.

MR. CODDINGTON: Thank you. Just to address that last comment and make a couple of other statements, IEEE 1547 actually requires provisions for monitoring of systems over 250 kW, and it's certainly not mandatory. But provisions need to be in there, and I agree with Mr. Steffel, that having that kind of monitoring and control could be very useful for the utility.

But there's another assumption that seems to be inherent, that exceeding 100 percent of that minimum load is going to be problematic. Indeed, in some cases it may. There may be high voltage. There may be equipment damage. But there are certainly systems out there that are designed to work well over 100 percent of the minimum load on a distribution feeder.

That's the exception, but I just wanted to clarify that there's no hard and fast ceiling, that 100 percent of minimum daytime load would cause a system to fail. I'm not recommending it. I'm just saying there are systems out there and it should be noted.

But the question at hand has come up twice. The question was is there a ratio that would be acceptable, and I think the two ratios on the table now are what do we have today, and that's 15 percent, which is equivalently 50 percent of minimum load. By the derivation of this whole process, we're defining 30 percent of peak load as being the defined minimum, and then you take half of that, 50 percent, and that's what the utilities are acceptable with today.

And then you've got, on the other side, some utilities in California looking at 100 percent of minimum daytime load. So I just would assert, for discussion, that we're somewhere in that range of 50 percent to 100 percent of minimum daytime load, and that would be, I guess, the area of discussion to perhaps settle that, or at least to talk about.

MS. KERR: Mr. Steffel.

MR. STEFFEL: Yeah. We have no disagreement that systems can be made to take backfeed, and we have backfeed. We have backfeed on feeders, we have backfeed on transformers. But the problem is they need to go through a detailed study, so that you do the appropriate modifications to the system.

So that's the only thing I'm saying. On a screen that's going to allow something to go through, you've got to be really cautious. The screen needs to be conservative. I mean we can accommodate those things, but you need to do the detailed study, find out what has to be done to upgrade the system to handle that.

MS. KERR: Thank you. Mr. Carranza.

MR. CARRANZA: You've got to be careful when you're talking about exceeding 100 percent minimum load. For example, let's say you exceed 100 percent minimum load in our system on one of our circuits.

The topology of our system is such that we have load tap changers that control the voltage that feed four, up to eight circuits at a time. You start pushing too much current back through that bus and out the LTC and into the transmission, what the LTC or load tap changer does is it lowers the voltage, thinking that there's lower load on the system, therefore keeping the voltage within limits.

When we start pushing too much current back through the LTC, back to the transmission, the reliability issue we experience is low voltage on the circuits that don't have PV or minimal PV on them. So as you mentioned, yes it could be, but we've got to be very careful when we're doing those type of studies.

MS. KERR: Mr. Sheehan.

MR. SHEEHAN: Thank you. I just want to go through a typical approach, and I use this "typical," because this is -- most utilities use nameplates. So when they get information from PV developers, they usually use the DC nameplate.

Well that's DC, it's not AC. So there is inherently a buffer in there of 15 to 20 percent, because that DC rating isn't the same thing as an AC equivalent. So this issue of being right up that 100 percent minimum load is something I think you need to be very well aware of.

Typically, we went through this discussion before, and that's why I think the approach that SMUD has taken was to do the calculation and then do the measurement, is really kind of what we want to get back to, to give that comfort level and to understand the risk.

This idea that you're going to be running up against the reliability issues, I think you need to be at least aware that there are better ways of measuring it and calculating. Traditionally, U.S. utilities do a lot of calculations. Europeans do a lot more measurement systems.

I think what SMUD has done is tried to measure the best, or bring together the best of those two practices, and trying to give some sort of comfort to what they're doing, because they're pioneering in this whole effort, and I think we need to be capturing those pioneering efforts.

MS. KERR: Ms. Peterson.

MS. PETERSON: Yes. I'll just list some of the additional buffers that are proposed within Rule 21, alongside the 100 percent minimum load screen.

There are two additional screens in supplemental review related to power quality and voltage fluctuation, allowing the utility engineer the chance to satisfy themselves that the interconnection of that particular facility will not exceed some of the limits that are set in other electric tariffs by the CPUC, for example.

Another form of buffer is what it takes to get into supplemental review. The settling parties raised the fee for supplemental review from $600 to $2,500 and the tariff allows 20 business days for the utility to complete the supplemental review process. So all those are forms of providing the utility engineer the opportunity to assure themselves that 100 percent of minimum load is a viable generating capacity limit.

MS. KERR: Go ahead.

MR. DAUTEL: Real quick, especially as we get back to the utilities. I don't feel like I have a good sense for what the utilities' position on Mr. Coddington's kind of translation of 15 percent screening to a 50 percent minimum load screen. Do you guys accept that, or are -- do you have concerns with that kind of logic?

MS. KERR: Mr. Roughan.

MR. ROUGHAN: Frankly, I think it's a little premature to suggest that, on a comment by Mr. Coddington a few minutes ago, whether we can accept it or not. I mean we do want to review that. I mean it's worth -- it absolutely is -- he's absolutely correct about the derivation of the 15 percent. We all accept that.

I think ultimately we really need some time to kind of think through that, whether that's an acceptable number or not. I think we'll still run up against what we're hearing from most of the other parties, that in many cases, with tens of thousands of line sections, the data, the measured data is not available.

MR. DAUTEL: I mean this assumes data is available obviously, or that you can get it through some process.

MR. ROUGHAN: Yeah, and again, the reason I'm just hesitating a tad is my prior statement about the net power that we're actually seeing at our substation breakers and reclosers, right? It's a net of the load on the circuit, less any DG that we don't have monitoring data available for.

As Steve mentioned, New Jersey, they don't know anything less than two megawatts. They know the nameplate, they know where it is. But they don't really know if it's operating or not, and they don't have any detail at the peak hour of the feeder or the minimum load hour of the feeder, what that particular generator was doing.

I think that's the real key here, is that if we had all these pieces of information, it would be really simple. We could say yeah, whatever percent of minimum load is perfect, right. But there's a lot of pieces of information that just aren't today available, but eventually will become available to us.

MR. DAUTEL: I see what you're saying, but I don't see why that puts any additional uncertainty into the minimum load comparison that wasn't already in the comparison to peak load.

MR. ROUGHAN: Well ultimately, even with that 50 percent peak load value, there was always a way the utilities could look at that and say yes, it's good to go.

It made it through the screens, or say because of, you know, the supplemental screens the California Rule 21 proceeding put together are other screens that utilities did anyway.

Every project, it's not just does it pass the screen, it's good to go; it's you go through the screens and then kind of look at what else is there, double-check what else is really going on in the area, you know, future plans for abandoning an old substation, future plans for upgrades.

There's lots of other things that the planning engineers are looking at, besides simply was it 14.9 percent of the screen, or was it 15.1 percent. And I do have to disagree with the fact that 15 percent is some sort of magic number that automatically jumps people into a detailed study.

In many cases, there's plenty of ways you can get around the 15 percent if you're over it by a little bit, if you don't have all these other issues in place and the engineers who work the area understand those issues best, and are the best suited to come up with whether that's acceptable to allow it to go online, with simply going through the Fast Track.

MS. KERR: Mr. Singh.

MR. SINGH: Yes. I guess I feel compelled that I've been hearing be careful, double-check, study some more. I get the position from a lot of the utility representatives here. Oh, we haven't figured it out yet. We've got to, you know, it will take some time. You know, it's tough, we've got to be careful. We get that.

In terms of innovation, there was a question earlier about us working with the utility industry. Speaking for a company that's actually owned by electricite de France, that's our parent company, there's a heck of a lot of innovation going on in our company, not only in price, because as has been mentioned, the price of PV has dropped dramatically, but in terms of quality, in terms of high penetration quality.

There's Solar Electric Power Association. They recently had a high penetration PV conference that was well-attended by both developers and utilities. So that dialogue is very much happening, and I'm sure a lot of the utilities here are a part of it. We are.

So I think for FERC staff and Commissioners, to rest assured that innovation is not the challenge here from the IPP side, and we do see some utility engagement on how to make this work. But the tone of just be careful, further study, further study is not going to work in our policy context today.

We can't just study this to death, and the places that are actually making the advancements on this are the places that have assertive policies. Sacramento's been mentioned, the State of California. We have to learn from that and leverage that to come up with better clarity across the country.

MS. KERR: Okay. We have barely touched on the two megawatt Fast Track limit, and we're getting close to lunch. So I would like to shift to that topic. So SEIA has submitted that the two megawatt threshold for eligibility for the Fast Track should be eliminated or increased to ten megawatts.

What would be the consequences, whether it's technical, safety, reliability, administrative, of increasing or eliminating the two megawatt threshold?

Mr. Carranza and then Mr. Lenox.

MR. CARRANZA: Well at least, for instance, you need, the first thing I would point out is the maximum rating that we typically lead our circuits to is 10 megawatts. So automatically when I tell you, unless there is a lot of load on that circuit that can handle the generaton that is being attached, it is not going to go through Fast Track.

Number two, we've been doing this kind of work for several years, and it's our experience that the further you move away from the two megawatt limit, the higher the probability that your project will not pass Fast Track. It's just the reality on our system and where the interconnections are happening.

The interconnections will probably happen faster if they were being developed in areas where the load centers were at, but the reality is that you can't put large PV systems where the load centers are, at least in San Diego, because that's where there's very little land available. And whatever is available is very costly.

So they are looking at going out to our rural areas. And as I mentioned earlier, our rural areas are not designed to carry that type of generation because the load was never designed to be there.

MS. KERR: Mr. Lenox.

MR. LENOX: Yes. You know, the system size cap is in effect just another rule of thumb that is being imposed. And again it currently puts you into this black box scenario.

The other screens that we're looking at all have a specific technical basis. I don't disagree that as you get over a certain size the probability that you won't pass some of the other screens goes up, but it doesn't mean that you should arbitrarily cut off the ability to be assessed under those screens just based on the size line because, as we all agree, every circuit is different, locations on circuits are different, and it's really, you know, a somewhat arbitrary rule of thumb.

MS. KERR: Okay, Mr. Carranza.

MR. CARRANZA: Just a quick response. You may consider that an arbitrary limit, but through experience we have found that if you go--if you move that up to 10 megawatts, let's say, and you want to push everything through Fast Track, you're just going to bottleneck everything. Things just aren't going to flow.

We're going to have to look at the Fast Track and everything from that point on is either going to go into what you fear to be an independent study. It's not going to work.

MS. KERR: Okay. Again, I'm going to keep moving along here. I'm interested, Ms. Peterson, in what deliberation of the Fast Track threshold was there in the Rule 21 proposal?

MS. PETERSON: Extensive deliberation.

(Laughter.)

MS. PETERSON: And honestly, I actually thought that between Mr. Lenox and Mr. Carranza they actually captured the issue quite well.

From the developer perspective, if I can recapitulate, is well let's take a look and see if this point of interconnection happens to be a place, because of these unique characteristics, where the project of X size above that size limit might actually make it through the Fast Track screens.

The utility perspective, if I can restate what Jose just said, is that you want to balance the number of applications into Fast Track so that it remains fast. Right now in the proposed reform, Fast Track should last 15 business days. And there are some technical considerations.

They are different, depending on the design and operation by each utility in their service territory, and so the ultimate compromise that came out of our settlement process established different size limits according to the interconnection voltage of the particular utility service territory. So it's 1.5 megawatts for San Diego Gas & Electric, and 3.0 for both Edison and PG&E up to a 21 kV interconnection.

I should mention that San Diego Gas & Electric has up to 12 kV interconnections in their distribution system.

MS. KERR: Okay. Mr. Roughan.

MR. ROUGHAN: If I could just suggest the fact that the 2 megawatt limit was not an arbitrary figure. It was actually worked out over many, many months in terms of the small gen interconnection proceeding negotiations of 10 years ago.

So the fact of the issues relative to what Jose and Rachel have mentioned about the voltage level you're interconnecting to, the fact that most projects at this megawatt size whether it's 2 or 10, are typically trying to connect to lower distribution voltages purely due to the cost of the interconnection versus connecting to 115,000 volt transmission at much higher cost for all the equipment that you need to buy to interconnect to a higher voltage versus a lower voltage.

So there's a strong desire to be able to interconnect at lower volt distribution. And a megawatt limit based on voltage is a much more accurate representation of what can be done. But the 2 megawatts is not arbitrary. It was a negotiated value in a prior process and potentially could be looked at, or should be looked at again going forward.

MS. KERR: Okay. So it sounds like perhaps a limit based on voltage might be an option? Because, I don't know, it sounds like that's where you ended up. I don't know if there were other options discussed during the settlement process?

MS. PETERSON: There were other options discussed ranging up into much higher megawatt sizes. Yes, we ended up at those size limits also based on the voltage of the interconnection. That just appeared to satisfy the wishes of all concerned.

I will state that the settling parties set out a recommended scope for phase two of our interconnection rulemaking, and they specifically want to revisit those size limits. That's driven by the developer community, that request.

MS. KERR: Okay. So any last comments for this first panel before we break?

(No response.)

MS. KERR: Or from staff?

(No response.)

MS. KERR: Okay, well thank you all for a good discussion. I would like to remind everyone that we are accepting written comments on the topics discussed today until August 16th. So if you want to clarify, or add detail, or even audience members or other members of the public, we encourage comments based on what was discussed here today.

So I would ask that everyone be back a little before 1:00 so we can start the afternoon panels on time. If you need suggestions for lunch, grab a staff member and we would be glad to help you.

There is a cafe at the end of the hallway on this floor in this building.

Thank you.

(Whereupon, at 11:37 o'clock a.m., the conference was recessed for lunch, to reconvene at 1:00 o'clock p.m, this same day.)

A F T E R N O O N S E S S I O N

(1:05 p.m.)

MS. KERR: Okay. Well, I'll come back for today's afternoon panel. The first panel this afternoon is a panel on collecting and sharing peak and minimum load data.

Our panelists are Bhaskar Ray from Sun Edison on behalf of SEIA; Dan Adamson from SEIA; Kristen Nicole from the Electric Power Research Institute; Roger Salas from Southern California Edison; Steve Steffel from Atlantic City Electric; Tim Roughan from National Grid on behalf of EEI; and Kevin Fox from Keyes, Fox and Wiedman on behalf of the Interstate Renewable Energy Council.

With that, I'd like to invite our first panelist, Bhaskar Ray, to give his opening statement.

MR. RAY: Thank you, Leslie.

COURT REPORTER: Microphone.

MS. KERR: Oh yeah. I forgot to remind everyone.

MR. RAY: Thank you, Leslie, and I appreciate the invitation and on behalf of Sun Edison, I'd like to thank both FERC staff and Commission for the opportunity to speak at the panel today.

I'm Bhaskar Ray, Senior Director of Engineering for Sun Edison, and I manage their interconnection activities there. So with that capacity, I'm here to talk a little bit about what we believe our official position has been, and then I'll definitely do a little bit more deep dive on the load data collection.

So you heard considerable amount of discussion, very fruitful and very productive in the morning panel, that there is a need for updating the FERC Order No. 2006, and that's what we believe at Sun Edison, that the SGIP procedures and the requirements do need the upgrade, because of the change of the circumstances for the solar electric generation interconnections, as we filed with our projects in the U.S. pipeline.

We strongly support SEIA's petition for update the SGIP rules, as they have failed in our ability to keep a pace with the rapid evolution of the solar industry and become barriers to entrants to the wholesale market. Recent experience with certain DG projects have very strongly asserted that process.

The current SGIP rules are an impediment to these renewable projects that we're trying to build and implement, because they're imposing unnecessary cost, prolonged delays and uncertainty in the solar energy development cycle.

The 15 percent rule in particular, we believe, is overly stringent and it triggers significant project delays, and we've had at least four projects that's encountered those delays. You heard a considerable amount of discussion in the morning where 14 parties in California have reached a settlement process for the Rule 21 in CPUC rulemaking as part of the recent reform.

I think that's refreshing in terms of understanding some of the process that went into it. A tremendous amount of work has gone in, which could become a framework for us to consider.

The centerpiece of the settlement, as we all know, is a significantly reform CPUC jurisdictional Rule 21 tariff, that can definitely act as source of ideas for updating te SGIP technical standards nationally.

The national best practice for the distributed generation penetration level has been introduced in that reformed Rule 21, under which the aggregate interconnected generating capacity can be equal to 100 percent of the minimum load on a distribution line section, and I believe SEIA's testimony talks at length about that.

As part of the settlement, the supplemental review screens have also been formalized, which I believe has a lot of merit for consideration, and clarified regarding the issues being addressed by the distribution provider. This is more robust look at site-specific impacts of power flow than the initial 15 percent review screen, as opposed to applying it globally.

Now let me talk a little bit about the whole load data collection process. The ability to determine the minimum circuit load, we believe, is integral to a more effective screening protocol. That is our process, that it would significantly help us when we do feasibility analysis for the research.

We feel that because of lack of enough load data, we're in a black box where we don't have enough transparency and understanding of what the system circuit loading needs to look like.

Although it is not the universal practice of the utilities currently to monitor the minimum load and the time of operation across the majority of their radial circuits, this should not be a barrier to implementation of the solar-specific minimum load screen.

That's what we have talked at length, in terms of understanding that the solar projects should be subjected to the minimum load screen, as opposed to the other technology-specific projects.

Sun Edison also believes that the utilities should be required to collect and provide peak and minimum load data on all circuits, where existing plus planned distributed generation additions would represent 15 percent or more of the circuit peak load to generation developers.

This likely would mean monitoring the load and installing good monitoring devices where they are not available, but we believe that the time has arrived where we need to seriously consider that.

As an alternative, Sun Edison also recommends that where actual minimum load data is not available, powerful software algorithms be extensively used by the utilities, and consultants be hired wherever there's the need for using that expertise and the specialized skills, so that load data can be estimated with reasonable accuracy, based on the old historical load patterns and standard load profiles for various customer classes, that many utilities maintain and update on an annual basis in their database.

Finally, the Sun Edison team feels that there's greater transparency to the load data that should be encouraged, more widespread access to load data, and known system limitations to accommodate any additional distributed generation, will greatly facilitate the developer site selection of investments, streamline or connection review, and enable fast track eligibility.

So let me wrap with some of the recommendations that we believe is what sharing with the panel is. We think a swift SGIP rulemaking action by FERC would be highly beneficial, and SEIA has proposed supplemental minimum daytime load screen for solar PV should be adopted.

Utilities should be required to collect minimum load data, or rely on well-established engineering techniques, to establish and estimate minimum load on circuits with significant PV penetration.

We also recommend that the utilities share this useful load data with developers by execution of NDAs, the non-disclosure agreements, because we've heard considerable amount of concern in terms of getting data out there. But if the developing world is willing to sign the non-disclosure agreements, that should alleviate the concerns associated with providing such data.

And posting such data in secured websites that developers can easily access upon execution of NDAs with utilities or regional reliability organizations. California ISO, for example, uses a similar approach, where market participants are allowed to go into their secured websites and download a tremendous amount of data, as opposed to having a public open forum. So we understand that concern.

Lastly, Sun Edison recommends that post-rulemaking, various working groups be formed among the distribution system stakeholders, to promote a more collaborative working environment, and implement transparent rules that provide a very clear and predictable path to interconnection for distributed generation.

We like the idea of having the working groups formed after the rulemaking as opposed to before, because that will slow down the rulemaking process. With that, I'd like to conclude my talking.

MS. KERR: Thank you. Dan Adamson.

MR. ADAMSON: Thanks, Leslie. I'm Dan Adamson of SEIA. I'm a Vice President of Regulatory Affairs and Counsel, and first just thanks to Leslie and everyone else on staff for all the work you've been doing on this issue. We know there's a lot of demands on your time, and so just by choosing to spend some time on this issue, we really appreciate that.

From what Bhaskar just said and the discussion this morning, it's obvious to everybody in this room that getting 100 percent of minimum load data, either actual data or an estimate, is really integral to making the SEIA proposal work, the Rule 21 proposal work.

You know, without that data or a reliable estimate, you cannot use the new screen. So it's very important. As far as the importance of the data, the Commission has a 20- or 30-year history, or at least 20 year history on the transmission side of using openness and transparency about what's going on on the transmission system, what type of capacity is and isn't available.

While this isn't exactly the same, it is the same in the respect that there needs to be transparency about this data. Developers need to have the same access to it that utilities have. You know, that's the way you're going to get open access. That's the way you're going to get transparency.

SEIA filed this petition in February, which is before the Rule 21 settlement was executed, and what we recommended at the time was that the obligation to collect and provide minimum load data be triggered when aggregate DG on a circuit line section is ten percent or more peak load.

So that would mean that in states like New Jersey and California and other areas where there are, there's a fair amount of penetration of solar and other DG on a circuit, that the utility or transmission provider would be required to provide that data.

But in other areas of the country where there's little or no DG, it wouldn't have any effect, and you wouldn't have to collect the data. So for example, in North Dakota, just to pick a state. It's unlikely a ten percent threshold would trigger a minimum load data collection.

I think for a lot of the coops, they were on earlier, I think, you know, a lot of them are in a position where the amount of DG on their system is slim to none, and so this wouldn't really have any impact.

We also raised the concept, which was later reflected in what Bhaskar said in Rule 21, that if you cannot get the data for whatever reason, that you would calculate it.

So now I'm going to talk about, I'm trying to follow the script here, you raised the issue of cost, because it does cost money to collect minimum load data, and some utilities have a lot of capacity already to collect this data. Many, and indeed I'm sure it's the majority, do not.

I think you've got to step back a little bit. There's a lot of utilities making investments in modernizing their distribution system, some under the ambit of Smart Grid, some under the ambit of, you know, just good practice. When they're doing that, oftentimes already they're including the capacity to monitor and report minimum load, and they should do that.

So if you're upgrading or modernizing your distribution system, you know, there's a lot of uses for this minimum load data, and you know, if we're going for a Smarter Grid, it would seem like a fundamental component of that would be not just knowing what the peak load is on a circuit, but knowing what the minimum load is.

So some of this can just be phased in over time, as other investments are made in the distribution system.

Just switching gears a little bit, you know, we're here today at FERC. So we're talking about FPA jurisdiction, not state jurisdiction, and even though I think this is an extraordinarily important proceeding, I'd be the first to tell you that, you know, FERC's jurisdiction over DG interconnection is narrow.

It occurs when there's a transaction involving an interconnection for wholesale transactions subject to an OAT. So that's a very definable universe.

So what that means is within its own jurisdiction, I'm going to assume, you know, that FERC will deal with the issue. But that even if you're using a line that's a dual use line, that's being used for both retail and wholesale interconnections, FERC has held previously, and I expect to continue to hold, that the cost allocation responsibility is with the state.

So although it is an important issue in this proceeding, it's important in terms of FERC's jurisdiction, if you go into dual use lines that are jurisdictional to states, this is going to be an issue of cost allocation dealt with by the states. My guess is that different states would deal with it in different ways.

In closing, SEIA is very eager, you know, we understand that this is a difficult issue. Some issues, I think, like the 100 percent of minimum load, at least in my humble opinion, black and white, you know, who pays for what is, you know, often depends on where you stand as where you sit.

So you know, we're eager to work with the

Commission, states, utilities and others, to come up with balance and effective solutions to the costs related to collection of minimum load data. Thank you very much.

MS. KERR: Thank you. Also just like we're having a little feedback, so if anyone has a cell phone close to a mic, please turn it off. Okay. Our next speak is Kristen Nicole. She is with the Electric Power Research Institute.

MS. NICOLE: Thank you, Leslie. Good afternoon and thank you for the opportunity to speak here today. As Leslie said, my name is Kristen Nicole. I'm the Senior Project Engineer in the Integration and Variable Generation Program at the Electric Power Research Institute or EPRI.

EPRI is an independent, non-profit mission-driven company performing research development and demonstration in the electricity sector for the benefit of the public. Our membership represents over 90 percent of the electricity base in the United States, and we're currently experiencing increasing growth in our international membership to the tune of about 15 percent.

It was interesting our colleague from enXco is here. We work closely with EDF as well as in France. For the past four years, EPRI's conducted a host of collaborative research efforts and facilitated dialogue amongst power system stakeholders, spanning all aspects of electricity generation delivery utilization, in fulfillment of this mission.

Myself, along with my colleagues Tom Key and Jeff Smith were co-workers on the Embril published paper referenced in the SEIA docket, updating interconnection screens for PV system integration. This effort was conducted in the context of many other cooperative research efforts we have going on at EPRI, related to renewables, storage, integration, interoperability, grid modernization, grid operations and planning, just to name a few.

As Mike Coddington introduced this morning, the white paper was intended as a stand-alone activity to provide a high level technical basis for discussion on this topic. So it's fascinating that it's led to such an intense conversation today.

As an organization, EPRI does not hold, take stands or hold political persuasions in policy-related activities. So we are, again, fulfillment of our non-profit mission.

So for our panel, we've been asked to address the issue of minimum load data as a potential measure for PV hosting capacity, in the context of the points Leslie distributed. The idea of the availability of certain types of data for this type of analysis, potential concerns associated with the use and sharing or transparency around the data, methods of minimum load estimation and alternate proposals to facilitate PV siting.

As mentioned in the paper, the 15 number, we talked about this this morning as well, so I'll try not to duplicate. But the 15 percent number originated from the half of 50, of 30 percent of peak load, which is generally rule of thumb for average annual minimum load.

The actual ratio of minimum to peak load varies widely based on many factors. These include, for example, the type of load being served on a particular circuit. It's important to remember that load is not the only factor. In fact, if there is one point that I could leave everyone with today, it would be that the interconnection process is unique, depending on the location in the utility jurisdiction.

The circuits, the system, the equipment on the system, the history of that utility, impedance. There's a host of different factors that will determine the outcome of how PV is going to perform in concert with the power system at that particular location. So the answer is that it depends.

The practice of managing PV penetration levels by simple benchmarking against load data works well in low penetration situations, as folks have identified today. Certain parts of the country, individual power systems are moving towards higher penetrations, particularly California, Hawaii, New Jersey.

For solar integration, it's important that codes and standards are continually reviewed and revised in accordance to maintain relevancy of the changing landscape, and folks echoed that this morning, with the activities going on in IEEE, as well as Rule 21.

The decisions made on this changing landscape are going to have implications for future generations. So in my opinion, it's important that policymakers strive to become as well-versed in some of these electrical engineering challenges faced by a variety of different parties associated with integration of DG.

These issues are complex and, in my personal opinion, won't be sorted out just today. So if the Commission decides to go forward with the working group or other stakeholder process in order to gather more information, it should be -- EPRI should be thought of, the staff and research that we conduct, as a resource for the community at large and the public at large.

It's known that PV has a strict daytime pattern based on diurnal cycles. So industry's interest in isolating daytime minimum load data as a factor is understandable and reasonable. I mean if you just look at the facts, PV's only on during the day. So it's a very unique characteristic of the generation.

The experience is that line section minimum load data is not widely available. Monitoring and grid modernization efforts, including Smart Grid, are increasingly producing a host of new data streams, and utilities are being bombarded with a lot of new data streams.

It's a matter of taking those new data streams and understanding how to effectively figure out which ones are necessary, how to use them. I feel like we're just at the beginning of this process for PV in general, and then also for some of the Smart Grid efforts that are underway.

At the line segment, it's rare that utilities will have minimum load data. Jose mentioned this earlier, unless the line segment happens to be a unique situation where it's representative of a full circuit. It's not uncommon for folks to have maximum or minimum load data through SCADA at the substation level or at the transformer level.

But if you have, you know, three to ten circuits coming out of that system, you don't necessarily have the clarity or the visibility below that. So that's a legitimate concern if the data doesn't exist, and then, you know, as folks mentioned, you have to understand cost allocation, understand how to monitor and collect that data.

So historically again, you haven't been able to get access to this data. This is really just the advent of digital recorders, including digital protective relays and others, the acquisition of system equipment that come on in the last few years.

I'm going to skip ahead here, just in the interest of time. But again, so line section monitoring again is not readily available. It's not impossible in order to collect this data, but it's extremely labor intensive; it's easier at lower voltages versus higher voltages.

So there are a lot of considerations in understanding where you're going to collect that information, and then also you may only be able to collect that information for downstream activities.

A positive aspect of availability of peak load data is that it's historically been collected as part of the system planning process. So you have, it's not just for one generation system. Utilities have institutionalized the need for peak load data. This doesn't currently exist for minimum load data.

So we're really, the impetus on collecting that data is solely based on this need. So if it was available, it's important to consider additional analysis that would be required in order to use minimum load data. Folks were mentioning earlier the potential of shifting load if you've got switching operations and load is shifting, or you have equipment that's down.

You might have a situation where, you know, you're able to collect minimum load data, but is that actually, you know, what's the uncertainty of that data? What's the activity below that data? So again, an analysis is also something to consider.

Online power flows have been mentioned as a solution to some of these problems for transmission system operations. This is feasible. For distribution operations, this is very new practice. So I'm sure, as folks will mention later, that type of future of being able to use that data is not readily available right now. This is a very new space for distribution system applications.

So in closing, EPRI is -- and I will just mention, we're working closely with the national labs, the CPUC, and the four major California utilities on a California solar initiative project, looking at alternative screening methodologies, with the goal of streamlining the interconnection process.

So this effort is underway, based on years of research. This is not happening overnight, but we did just get the project. So over the next several years, we'll be looking at trying to form a technical basis for the future of the screens, and again, this is based on the idea that every system is unique, every circuit's unique, so how can you take such a diversity of circuits or scenarios and figure out a way to generalize it, or at least condense it so that it is usable in broader scenarios.

We're using, you know, our existing experience in power quality monitoring. We have a deep distributed PV project that's going on, where we're collecting over -- we're collecting data from about 200 spots around the country.

We're using this data in our simulations and our open DSS models, to better understand and characterize some of the activities going on in the circuits, and we are working collaboratively with a lot of stakeholders in the room. So thank you for your time.

MS. KERR: Thank you. Next, we'll go to Roger Salas.

MR. SALAS: Thank you for the opportunity to participate in today's panel discussion. My name is Roger Salas, and I am a Supervising Engineer for Southern California Edison.

In my current role, I supervise a team of engineers who are responsible for reviewing generator interconnection requests, and for performance system studies under our FERC jurisdictional tariff, as well as under the

California Rule 21 tariff.

I respectfully encourage the Commission to reject SEIA's proposal that the transmission owners be required to collect and provide minimum load data to generator developers.

Our experience over the last three years with the review of approximately 590 applications under the SGIP, demonstrates that the current SGIP fast track process works as intended, by separating projects that could interconnect quickly without safety and reliability concerns, from those projects that require further study.

At SCE, the 15 percent screen is not the most significant factor as to whether a project meets the fast track requirements or not. Rather, the most significant factor is whether developers choose to propose projects in a transmission-constrained rural area, as opposed to proposing projects in a non-transmission constrained urban area.

Since January 1st, 2011, SCE has completed analysis of approximately 95 fast track projects. 31 of these projects were proposing transmission-constrained areas. Only one of the 31 projects qualified for fast track. The other 30 projects failed at least two of the other screens not related to 15 percent, related to the transmission constraints of the location where they're proposing to interconnect.

On the other hand, of the 64 projects that we're proposing in non-transmission constrained areas, 50 of the 64 projects passed the fast track requirements. This demonstrates that the existing fast track process is appropriately distinguishing between projects that no potential for safety and reliability issues, from those projects that require further study.

Furthermore, complying with SEIA's request will impose burdens, both in terms of resources and expenses, without delivering the benefits that the generator developers are expecting. In its request, SEIA proposes that utilities publish minimum and peak load data for all circuits with penetration greater than or equal to ten percent of the peak load.

However, the 15 percent screen does not apply the circuit level, but at the line section level. Looking at the SCE-distributed system, while we do have load data on approximately 5,000 line sections, we do not have load data on approximately 33,000 line sections.

For these line sections, SCE will be required to install new devices and communication systems to determine whether such line sections meets the ten percent load requirement. Furthermore, simply obtaining raw data is not enough. The load data will need to be analyzed before it could be provided to project developers, requiring additional engineering staff to verify and determine appropriate minimum loads for all line sections.

Proper verification requires trained engineers with knowledge of SCE systems and conditions. These measures are simply not practical and will not address SEIA's concerns. As explained previously, the most significant factor for the fast track analysis is whether the proposed project location is within a transmission-constrained area or not.

Approximately half of the line sections in SCE's service territory are in transmission-constrained areas. So publishing minimum load data for these sections will not enable more projects to pass the fast track.

In fact, even if these projects in these areas pass the 15 percent screen or even the 100 percent minimum load screen under supplemental review, these projects will ultimately still have to go through the study process, as these projects will fail other screens related to transmission problems.

Nor will SEIA's proposal provide any meaningful help to projects seeking to connect in non-transmission constrained areas because the existing fast track process works well for those projects.

Since January 1st, 2011, approximately 78 percent of fast track projects in non-transmission constrained areas have met the fast track requirement. They have proceeded under the fast track process. The 78 percent passing grade speaks for itself. The fast track process is working in the non-transmission constrained areas.

In conclusion, my experience with the fast track interconnection process has shown that it is working, and it is not unduly discriminating against solar developers. Of course, I'm interested in hearing other parties' perspectives in this issue, and look forward to further discussion today. Thank you.

MS. KERR: Thank you. Steve Steffel from Atlantic City Electric.

MR. STEFFEL: Thank you, Leslie. Steve Steffel representing PEPCO Holdings, and Atlantic City Electric is one of the --

COURT REPORTER: Would you turn your mic on?

MR. STEFFEL: Oh, sorry. Steve Steffel representing PEPCO Holdings, and I'm the department manager of Distributed Energy Resources Planning and Analytics. We have the three utilities, and Atlantic City Electric in southern New Jersey is the most active area. But we have solar going in the Delmarva Power and Light area, and also in this area of Washington, D.C.

Looking across the board on the feeder data that we do have, there are obviously some feeders that don't have this data. They have older data collection systems, metering and so on. Some of them are manually read, and of those feeders that do have this data, typically this data has not gone through scrubbing process.

So it would be, you know, starting there, that would be an extra effort to do all the error checking and make sure we've got correct data. We don't have typically of any feeders that have this load data by section. Perhaps there's some device out there that we've put in that may be recording it, but it's not something actively being retrieved by our SCADA system.

Things that would affect the accuracy and so on, phase imbalance, metering the inter-inaccuracy for estimation error would need to be accounted for if you're going to estimate the minimum load. And again, I had mentioned before, you need to take into account the minimum phase.

There are phase imbalances, 15 to 30 percent at times. They get balanced every so often, every few years. But you've got to really be careful not to overlook that. The installed PV will masking some of these loads, and there's changes due to weather, economics, the DERs being on and off, and all of that has to be taken into account.

So just publishing a raw piece of data is not going to be meaningful by itself. All these other things have to be taken into account. To make it even more useful, the pending systems, those with in service states after that load data was picked up, have to also be taken into account, which increases the complexity to make that data useful and meaningful, and something that can be actionable.

In addition, there's distributed automation and restoration schemes that are in existence on many feeders, and are being implemented throughout our system to improve the reliability of the system.

If the practice of providing the data is started, this type of data would have to be published in a public website, to ensure that there's no preferential treatment, and it would have to be updated fairly frequently to be of value. So there is a significant effort that would need to be made on the part of the utility.

Since there's a lot of other screens and a lot of other things that can limit or trigger a study, and it would not ensure that the developer could put a system in of a particular size at a certain location on the feeder, we feel like, you know, it's a lot of effort that may not provide as much value as was intended.

The other thing is it was brought up in New Jersey, and when the desire for this data was brought up, one of the major issues was cost. Who would pay for it? We never had the solar industry sign on to paying for it completely. So it would obviously be the rest of the customers that would be paying for it, if we actually do move ahead and do it.

I mean there's measurement equipment, there's personnel time for all the analytics, and then the posting of the data and maintaining of that data. So I think those things are significant to consider and weigh against the value of that data being provided. Thank you.

MS. KERR: Thank you. Tim Roughan from National Grid, representing EEI.

MR. ROUGHAN: Thank you again for giving me the opportunity to speak like this morning. So going through this particular question, I think ultimately, you know, Dan is correct, that there's lots of activity, lots of planning for reliability enhancements, distributed automation, to increase reliability of the system, while maintaining low delivery costs.

I mean it's, I mean folks who have been in the regulatory process know it's quite a process to get a rate increase put through your state regulator. So when we have these long-term plans, and if they've been approved, they need to go down the same path. There's a lot of reporting requirements to show that you're making progress on putting in this equipment.

If and during, in the middle of that process you now have to adjust or modify where you're putting your equipment because a circuit gets to ten percent saturation for PV, that will simply result in some inefficiencies of that deployment.

We need to make sure we work with what the regulated utilities are, the distribution levels are already doing, and not impose additional requirements on them, that require us to go back to each state regulator to get additional funding to do other work that we hadn't already talked about.

I talked this morning about the three, five, ten year capital plans most utilities go through and propose to the regulator. Within those capital plans are things like DA, are things like Smart Grid enhancements, are things like communication and controls and intelligence on the system, so we can automatically switch devices around.

So those have been set up and are in place and we'll work on those plans going forward. Again, interrupting that plan obviously won't be the most efficient way to move forward, because ultimately getting the minimum load data is going to be a long term process. It won't happen overnight.

I know for most utilities have significant data at the substation level, at the newer substations. We all have plenty of substations that have been out there for many years, that likely don't have the sophisticated metering required. Many of the older substations only have peak load measurements.

They don't even have the ability to collect minimum load without replacing all the metering equipment, which is typically done in an upgrade when that substation then comes up due for an upgrade, if you will. So again, slowly deploying this type of equipment is really the way to get this minimum data.

We had an extensive conversation this morning about the true value of that minimum load data. I mean I'm still of the opinion that that's just a piece of the pie to look at, and to use it as a be-all to end-all screen will limit the flexibility of the distribution utilities, in terms of working with their systems, working to meet the local customer needs, and the reliability needs.

New customers come in, new customers go out. You know, a customer who had a three shift operation two years ago goes to two shifts. Now they don't have any load on that Saturday and Sunday afternoon, where typically your minimum daytime loads are during the late May or early October periods up in the Northeast for example, and that can just change.

We won't know that that entity went from three shifts to two shifts. Until they volunteer and call us, we simply won't know. So there's a lot of moving targets here, and putting together, putting out a rulemaking and then putting working groups together to try to figure the rule out, I think, is going the wrong way.

So we want to point to set up the working groups up front to work out all the details. So when a rulemaking is actually established, you've got that breadth of experience and knowledge to work off of, versus pushing forward a rule that frankly will undermine significantly some utilities' ability to look further into the issues about the DG looking to be interconnected at that site.

We talked a lot about the locational aspects of these projects. I said it this morning. These projects are being built on the fringes of the territory. They're being built in the rural areas. They're being built on the weaker parts of the system.

So whatever the loads are out there is kind of immaterial, if the conductor site is already a problem, or if the voltage regulation issue is already a problem.

So I think we're kind of getting ahead of ourselves, trying to figure out how to get the minimum load, because we really haven't sorted out the answer. Is that really what we want to get? What's the problem we're trying to solve?

Just because customers don't pass the fast track doesn't mean they don't, they aren't or cannot be interconnected. There is a study or potentially upgrades. But projects, we in the current phase of these multiple megawatt projects, which have only been a couple of years for us, we haven't seen any drop out.

Even with a study, they're going forward. They're getting built. They're producing solar power. So we have yet to see a project that fails a fast track not go forward and still be built. Now perhaps it's happening in other parts of the country. We're still only in the first two years of it up in the northeastern states.

But realistically, I think we have to recognize what problem are we trying to solve here. I think we first need to have that discussion amongst the technical parties and the different groups of utilities, and of the industry, to come up with that set of problems we're trying to solve, and then come with solutions, and then a rulemaking would be the appropriate method. Thank you.

MS. KERR: Thank you. And now to Kevin Fox of Keyes, Fox and Wiedman, representing IREC.

MR. FOX: Thank you, Leslie. Thank you. My colleague, Mike Sheehan, appeared on the first panel and provided a little bit of background information on IREC. As Mike mentioned, we are a 501(c)(3) non-profit, non-lobbying organization that is presently active, working on interconnection reform efforts in about a half dozen states including California, Hawaii, Washington, Massachusetts, New Jersey and also, of course, are active here at FERC.

In the half dozen states where IREC is presently active, we see three developments driving interconnection reform efforts, all of which were touched on briefly this morning by panelists.

First, utilities are seeing a significant increase in interconnection requests in many parts of the country. Second, higher penetrations of distributed energy resources are being interconnected to our country's distribution systems. Third, new programs like feed-in tariffs and community renewables are bringing larger generators online that do not primarily serve on-site load.

These are new conditions that have emerged primarily in the last three years, well past the time that FERC adopted the small generator interconnection procedures. Much of the increase in interconnection activity we are seeing is due to a rapid increase in solar PV deployment.

According to the Solar Electric Power Association, in 2011, utilities interconnected over 62,500 PV systems. To put this in perspective, about 350 non-solar PV plants larger than one megawatt were expected across the United States in 2011.

That means that for every non-solar PV plant larger than one megawatt, utilities processed 175 solar PV applications. Conservative forecasts indicate that this number will grow to over 150,000 interconnections by 2015.

SGIP was not designed to handle this volume of interconnection requests, nor was it designed to address higher penetration levels that we are now seeing. Nor was it intended to facilitate larger and more complex generators that are increasingly being interconnected to our nation's distribution systems.

The impact of these market changes has been most significant in states like California, Hawaii, New Jersey and Massachusetts. However, these states are merely precursors. According to the Solar Electric Power Association, 22 utilities interconnected more than 500 PV systems to their electric power systems in 2011.

In fact, utilities with the highest cumulative solar watts per customer installed, now include utilities in Georgia and Tennessee. For these reasons, IREC believes the time is now right for FERC to update SGIP, to it continues to facilitate solar market expansion.

California and Hawaii have both made attempts to keep the number of applications manageable, by providing more information to developers in advance of a formal application being filed. In both states, it has become apparent that developers are filing multiple applications to identify low cost places to interconnect.

In particular, developers may file several applications for the same projects, or portions of projects on nearby parcels, looking for how much capacity can be developed before expensive upgrades are needed. Hawaii and California are pursuing approaches to reduce the number of speculative applications.

One approach is to provide more information about low cost places to interconnect up front before a formal application is filed. Providing this information has the additional benefit of making better use of existing distribution system infrastructure, without requiring significant upgrades.

In California, stakeholders have proposed a pre-application report, to provide specific information on proposed points of interconnection. Rachel Peterson from the California PUC discussed this briefly this morning.

Against this backdrop, IREC would like to make three recommendations in response to the specific questions posed by FERC staff.

First, IREC believes the pre-application report should be incorporated into SGIP. Section 1.2 of SGIP currently allows for the provision of relevant information. But this section does not provide time frames for providing information, or a specific list of information that must be provided.

It also does not provide reasonable compensation to a utility for time spent providing this information. IREC believes SGIP Section 1.2 should be modified to include greater specificity. Specifically, we endorse the pre-application report content of the proposed California Rule 21 reforms.

We believe that this is the best means to provide developers with information to facilitate site selection and streamline the interconnection process.

Second, to the extent minimum load is a relevant consideration in the interconnection process, and IREC believes strongly that minimum load is a relevant criterion, this information should be provided in the pre-application report, so long as such information is readily available.

We do not believe the pre-application report should require utilities to make calculations or estimations, but rather should be a means of sharing information that is readily available.

Third, we believe FERC should not mandate a specific means of collecting or estimating minimum load data. We believe that there are a variety of approaches that utilities can use to calculate or estimate minimum load at the line section. We appreciate the fact that this data may not be readily available, and that the current infrastructure may not be installed, so that utilities have it ready. But we do believe that utilities have the means to calculate or estimate minimum load.

This includes making use of Smart Meter data and SCADA systems deployed at substation distribution feeders. It also includes use of power flow modeling and the use of standard load profiles for different customer classes. Different utilities have different tools at their disposal currently, and we believe they will be developing additional tools over time.

We believe utilities should have the flexibility to use the tools that they believe are most cost effective for their situations.

Finally, we believe that requiring the use of minimum load data in the interconnection process will give utilities a reason to collect this data. Once it is collected, it can be made available in the pre-application report, and applied more readily in the supplemental review screening.

IREC believes any concerns associated with providing such data to generation developers through a pre-application report can be easily addressed through simple non-disclosure requirements. Thank you.

MS. KERR: Thank you. So we have some staff questions, and no Commissioners with us at this point. So we'll get started. Each of you, I think, touched on this a little bit, but I want to ask it again, and try to drill down a little bit, the extent to which actual line section minimum load is currently available, if you have a feel for that either for your utility or for regions of the country.

If it's not currently available, will it be available in the near future, and if you can give us some estimate of what time frame you think that is? If it's not currently available, what are the obstacles to collecting and providing that data? Again, like this morning, if you could just indicate with your name plate that you're interested in answering. Okay. Mr. Salas?

MR. SALAS: Yes. As I said in the opening statement, the numbers that I provided are pretty much out of our databases, where I stated that 33,000. So altogether, we have approximately 38,000 line sections more or less. 33,000 line sections do not have any data whatsoever.

MS. KERR: Does that just include minimum load data?

MR. SALAS: No. No load data whatsoever.

MS. KERR: So you couldn't get peak load data on those either?

MR. SALAS: We would have to go under some estimation if we needed to, on a line by line section when necessary.

MS. KERR: So if you had an interconnection request under the 15 percent screen, you would still have to estimate that data on those line sections?

MR. SALAS: Absolutely. In a line by line section, you have to do it and some are using different methods, different tools.

MS. KERR: Would those same tools for estimating peak load, could they be used to estimate minimum load?

MR. SALAS: Could be. But again, it would make it more complicated. But again, doing it on a line by line section during like a supplemental review process, where you have, the engineers have more time to determine what type of customers we have in the line section, you know.

We can look at some meters. We can, you know, look at some trends, whatever. Yeah, we could do it, but again on a project by project basis, line by line section, you could do it, but definitely not on 33,000 sections.

MS. KERR: Could you do -- you talked about doing that as part of a supplemental review process. Are you talking about a general supplemental review process like in the current pro form SGIP, or in the supplemental review process similar to the California Rule 21 process?

MR. SALAS: In California, we do both. In other words, you know, what we proposed under the Rule 21, California Rule 21, it's the same screens that we utilize under our FERC jurisdictional tariff. In other words, the tariff allows us, it's general enough where it says if any of the ten screens fail, you can proceed to a supplemental review.

It doesn't really say the exact steps and so on and so forth, but we as engineers, we know what those steps are, and we implement those steps both under the FERC jurisdictional tariff, which are the same as what we would apply under the Rule 21 tariff.

MS. KERR: Okay. Just to clarify, so the proposed Rule 21 settlement, those are the steps you're talking about in the supplemental review screens? Okay. That's what you would use currently to do a supplemental review? Okay, thank you.

MR. SALAS: And again, that's the reason why we have the percentage, 78 percent of projects that pass fast track under the, in the non-transmission constrained areas.

I would say about 75 percent of those failed the initial 15 percent, but went into the supplemental review, in which we looked at the three additional, voltage regulation, safety and the three additional screens under this, that we would outline under Rule 21. That's how the percentages, it's much higher.

MS. KERR: Okay.

MR. SALAS: But to answer the original question, you know, 33,000 line sections we don't have line data for. We will have to install very large amount of equipment to be, and communication systems, to be able to collect the data.

Even once you had the data, again as I stated in my opening statement, you still have engineering staff that needs to look at that data, to analyze each line section. It's just an incredible amount of work, for really I don't believe that is really necessary for what's intended right now.

MS. KERR: Just one more question. If you did have to estimate either peak or minimum load, because it sounds like it's a similar process, about how much time does that add to the interconnection process?

MR. SALAS: Well, I think the time that we allotted in the Rule 21 reform already accounts for that.

MS. KERR: Okay.

MR. SALAS: So you know, I believe it's 15 business days or something like that that we have the supplemental review, that we allow as the time to do that.

MS. KERR: Okay, okay. Okay, Ms. Nicole.

MS. NICOLE: So just to echo again, from my understanding, and this is just ballpark, because you're going to have, again, every system's different, every, you know, section's different. You have different equipment that's, you know, some of it's newer. I mean folks have referenced Smart Grid and AMI. We all know that that's not a reality for every meter in the country.

So you have to bucket out different parts of the system, and just in your mind bucket out you're going to have different data availability for different types of situations. So just to kind of ballpark, from my understanding, you can get -- within SCADA systems, you can get min-max.

But you're going to get that more utilities have those type of data acquisition systems at the substation or transformer level, so it's upstream. So you have this kind of gap in knowledge, where folks will have, you know, you will understand minimum load, you know, over a year or so at the substation level for folks who have those systems, which is not everybody.

I would say, and folks can correct me if you think I'm wrong, but you know, around 50 percent or so. It's not every situation and everybody's different. However, once you have those types of measurement points, then you have to get into the specifics.

If you have certain types of equipment out there, for example if you have digital protective relays, those would be able to give you some sort of --they would ping back some sort of, communicate some sort of information back to a data acquisition system, for example. But it would only be through a specific period. It would be like in an event or something. Then it would ping back that information.

So a lot of the, or cappings (ph), for example, and the newer ones could communicate back that type of information. Not every, you know, line section or line's going to have those types of equipment on there. So you just have to work with whatever's out there, whatever is in the planning to be built.

That being said, you know, over the next few years, as Tim was mentioning, folks have three, five, ten year plans for build-out, and so it's something that we should be thinking about in the future. You don't have that institutional planning capability for minimum load data versus peak load data. So it's just not something that folks have done historically.

MS. KERR: So on these build-outs, absent a regulatory requirement, is minimum load something that, you know, if you're upgrading your system or doing a Smart Grid program, is that something you would be looking for, looking to install equipment?

MS. NICOLE: I mean from my understanding, that's not -- what would be the purpose for needing it? You would need it in case a PV developer wants it. You wouldn't necessarily need it for a planning purpose, because you're planning for capacity.

So you're, so folks aren't necessarily building down your system requirements.

MS. KERR: Okay, thank you. Mr. Steffel.

MR. STEFFEL: We have a number of feeders that they would maybe constitute the line section, in which case some of them have and some of them don't have, just like others have mentioned, that there's historical data.

There would probably be two sources of getting this demand-type data that you can roll up to line sections. One would be SCADA equipment that you actually put out on the feeder. Number two is if you have AMI and you can roll it up into feeder sections.

We have had AMI efforts in, I guess, two-thirds of our utility, and in the one area where we have the most solar, the Public Service Commission has not wanted to have AMI in that area. So in that area, it's kind of difficult to put that together by line section.

As Kristen mentioned, we don't have as much of a purpose to focus on minimum or peak. We're focused on meeting the peak load, and making sure that we've got proper voltage and we're meeting the, not overloading equipment and so on.

I think that in time, this type of data will be available. But I think it's kind of premature to try to request utilities to provide it. The problem is that in the discussions we had in New Jersey, where you know, this data was desired, the solar developers and so on really didn't want to pony up to the cost of collecting it and putting out the measurement data.

So somebody has to pay for this effort, and it's not an insignificant effort. As I said, putting out unscrubbed data and not taking into account all the other factors, doesn't make the data very useful.

So to get good data out there that can be actionable, there is a significant cost, and we've got to either bite the bullet and somebody has to pay for it, or you know, we have to say well, it's not worth the value at this point.

MS. KERR: Is there -- Mr. Fox mentioned the California reports that developers pay $300 to receive. Is that some sort of mechanism that would work to pay for the data?

MR. STEFFEL: Not when it costs, you know, tens of thousands of dollars to pick up the data, on a circuit or a section.

MS. KERR: Okay. Mr. Roughan.

MR. ROUGHAN: Yeah. I mean there is no reason for us to collect minimum load data at all today. It's not what we design our system around.

We design our system around providing reliable service to our customers, and be able to do that under circumstances where you've got outages, feeders, storms, you know, care accidents, squirrel incidences, etcetera. So that's -- it's all driven around that.

I did want to just clarify my comment about utilities have long term, three, five year plans, ten-year plans. That's only once the regulator has agreed that the cost versus the benefits of that deployment are right for that state.

Right now, we're still going through significant pilot efforts on Smart Grid. All the DOE funds that went out there, a lot of pilots. Everyone's waiting to show that the cost to make the system smart and advanced metering and the customer interaction is less than the benefits you'll derive.

That hasn't been proven out in all cases, where the regulators of the states realize that if they agree to a multi-tens of hundreds of millions of dollar effort, because this is a significant amount of work we'd be doing over time, they need to be comfortable that the benefits of that price tag are worth spending that money, because we're talking about a revolutionary change in what we're doing to the utility distribution and transmission systems.

And again, they need to be very, very comfortable before they give us the green light to put in that five year plan or whatever it is, that the costs we've estimated are lower than the overall benefits. And until that's in place, there isn't a plan that's going to provide minimum load data for most of those line sections which we've been talking about.

MS. KERR: Okay, thank you. Thanh, do you have a question?

MR. LUONG: Yes. I just had a clarify question. You know, so far I heard that there's a lot of area that now have no peak load data or even minimum load data. What happen if a PV would like to connect to that area, not even a fast track, and then you had to perform a system impact study? What data do you use to perform the system impact study?

MR. SALAS: Is that question to me?

MR. LUONG: For anyone, you know, engineer, that you can provide a system impact study? I heard a lot that you had no information. So how do you perform the system impact study with no data?

MR. SALAS: Well, during the system impact study phase, we do have the time to look at, you know, again the information, the type of customers that we have, the load profiles and so on.

So we're not saying that we don't have any data. We're saying that it's not available to just publish and click a button and say here's the minimum loads. So we know the customers; we know who are, which customers are on our circuits, what their load profile is, and we know the peaks, and we can probably do a good estimation on the minimums. That's what we use for study purposes.

But again, we do that on a project by project basis, when we have the time and the resources and the funding to be able to do such research.

MR. DAUTEL: I guess I have a little tweak on your last question, which is not why are they putting in minimum, or is it worth it to put in the minimum load collections?

But I assume there are times when They're putting in meters to do the peak load collections, and I would be a little surprised if the incremental cost to add minimum load connection to equipment that can already do peak load collection is significant.

I don't know if that's a question or a comment. Does anyone have any reaction?

MR. ROUGHAN: Well, I think you're right. Once you upgrade that substation, you put in the full metering suite of what you normally put in for a new substation.

You're right. You've got data. You've got plenty of information. Minimum, maximum, you've got all the data, when that substation is being upgraded.

That's at that substation. That's at that high level which Kristen is talking about. But there's still relatively few times when you're putting that peak load data at a line section, at a feeder that's out, equipment out on the circuit.

So yes. When we're upgrading the sub, you get it all. It's just when we're talking about the line section piece here, that's the challenging piece.

MR. DAUTEL: Right. I guess I'm primarily interested in how this applies to the line section. So you're saying they don't, they often don't have that equipment and there's no plans to put it in. But then I'm left assuming that they're doing mostly estimations today then. Would that change significantly if they started estimating minimum load data, I wonder?

MS. NICOLE: So yeah. I would say, I mean the 15 percent idea came out of an estimation. 30 percent is an estimation. Whenever, I forget who mentioned it this morning, I think it was Mike Sheehan, talking about the SMUD example, where you're trying to close the gap between estimations and measurements.

So anytime you can reduce that uncertainty in your estimations by improving your measurements, and like I said, there's a couple of different types of ways to validate those estimations with different measurements.

So you could do SCADA. If folks had a new substation with SCADA capability, you could potentially flip a switch or maybe it comes out of the box with all types of data. So it wouldn't necessarily be a huge burden in that instance. However, you're not going to find every utility with that type of system.

So you're going to have different scenarios within a utility, or you might have different utilities. My personal thought on this would be that it might disproportionately impact folks who, you know, are IRUs, versus a coop, versus a muni, the extent to which they are investing in sort of, you know, SCADA activities.

Then along the line section, you would have literally sort of a monitoring device that you'd have to install. So you would purchase the equipment, which would be essentially a few thousand dollars, depending on what voltage level you're at, and then you'd have to install it and maintain it.

And then to Steve's point again, it would be once you have that data in place, pulling it back, because again it's only a time stamp, right? So making sure that any data that you have is put into context of other things happening out either, you know, below the transformer level or amongst different feeders.

So it's not that it's impossible; it's just again, it's a matter of how much time and how much cost potentially in the different types of ways that you could collect data, and then get a precision on exactly what data you're looking for, and then what's the value of that data at the end of the day.

What we're doing within EPRI with our CPUC project is trying to get away from this idea that you're really just looking at load data. You're looking at, you know, the type of circuit, how can you characterize different types of activities on the circuit, because you're going to have, you know, many different types of circuits out there.

So is there a way to take some of these unique characteristics and develop methodologies to understand certain types of behaviors, and then validate those to understand PV hosting capacity. So the idea would be to, instead of having one number, like a 15 percent number, it would be more of a customized percentage, or not percentage, but a customized penetration level.

So you know, one particular area might be three percent, one might be 50 percent. So that's kind of the direction that we're going in, is away from a one-size-fits-all approach, with penetration and with maybe one data point, but moving more towards sort of an understanding that since you have so much diversity, how can you customize it or create some sort of methodology or platform that would again streamline the interconnection process. It just makes it easier, and frankly more accurate potentially, if we're successful.

MS. KERR: Is the idea to make a hosting capacity idea transparent? It sounds very individualized, so it might be difficult to describe?

MS. NICOLE: No. I mean we're -- no, it's extremely transparent. I mean the research that we're conducting, it's repeatable. I mean we're working with National Labs and with CPUC. So it's going to be, it's public research.

You know, the lack of transparency, in my opinion, is because it's complex. It's not because there's not information out there or forums where people are having a lot of conversations about how to best address these issues.

It's just that it really is a challenging problem, and you know, you talk on what's happening with PVs specifically, and you look at demand response and electric vehicles, and you try to take all of these challenges in context, and it's really not an easy challenge for engineers.

MS. KERR: Okay. Michelle.

MS. DAVIS: This is just a follow-up question for Mr. Ray and Mr. Fox. You both mentioned the execution of non-disclosure agreements to keep minimum load data secure, and I was hoping you could expand upon the precise concerns associated with making that kind of data and presumably peak data available to generators, generation developers.

MR. RAY: I think in the past, what traditionally the developing world has heard, is that there is considerable concerns about putting such data out there in the public domain, where there are some security concerns.

So the revival to that argument has been that if certain developers who have projects in the utility queue, that has legitimate business reason to get that data, would utilities be willing to share some information under a non-disclosure agreement, where they don't feel that they have to put the data in a completely open public forum?

Only a handful of participants or stakeholders that really have a legitimate business reason to get such a data, should be able to get access to the data under NDA. Does that take that security concern from the table?

MS. KERR: Did anyone else -- I can't remember who else you wanted to ask that question of.

MS. DAVIS: Mr. Fox mentioned it.

MS. KERR: Okay. Mr. Fox.

MR. FOX: Sure, I agree with that answer. I think what IREC is proposing here is to provide information, not through a publicly-disclosed website that would make information about utility infrastructure generally available. California and Hawaii both do that currently.

That could certainly be helpful, and I think that those states have pursued that approach, because it helps facilitate achievement of their policy goals. They want DG to go into particular higher value locations, and providing a map that demonstrates or shows where those higher value locations are is helpful to achieving that goal.

What we're talking about here is providing information through a pre-application report, where information on a specific point of interconnection would be provided to a developer requesting that information, so there isn't that sort of public disclosure issue.

MS. KERR: And you've held your name tag up for a while. Did you have something else you were going to answer as well?

MR. FOX: I do. Thank you, Leslie. I think it's important to bring the discussion about metering and the gathering of information generally sort of back to the policy issue at hand here. You know, we appreciate that not all utilities have minimum load data on the majority of their circuits.

So therefore providing that information today in a pre-application report would be challenging. As I mentioned, we think it's important that the pre-application report only require utilities to provide the information they have at hand.

However, I think it's important to stress that that does not mean that minimum load criteria cannot be incorporated into a supplemental review process. The reason is we want to avoid a chicken and egg problem, where the answer doesn't become "we don't have it, so we can't use it. But it's not needed, so we don't collect it."

Because that status quo gets us nowhere, and we'll never have this information. Roger talked about the supplemental review process in California, and how that works, and the fact that it gives utilities an additional 20 business days, I believe it is, and $2,500, so that they're compensated for the calculation or estimation of what the minimum load is.

You know, that is the approach that we would certainly endorse. Then as that happens, more data will be made available. I think, you know, there's an important point that shouldn't be overlooked here. Kristen, Steve, Tim, I think, all made the point that there's no reason to focus on minimum load data today.

As I mentioned earlier, incorporating minimum load criteria into the supplemental review process will give utilities a reason to collect this data, and as they collect it, they'll then be able to make it available through the pre-application report.

MS. KERR: All right, thank you. Mr. Steffel.

MR. STEFFEL: Just a quick comment. You had mentioned a little question on the hosting capacity, and we want to acknowledge EPRI's doing an excellent job on that. There's a few pages at the end of the handouts we gave that are the results of their hosting capacity on the rural feeder. So if you're interested, that has a little bit of their methodology in it.

MS. KERR: Okay, thank you. Mr. Salas.

MR. SALAS: Yeah. I wanted to comment back on Thanh's original question, I guess, as far as, you know, I guess his question was related to once you do a project, you know, what does it take to put additional equipment out there, to obtain the minimum load data?

One thing that we have to keep in mind is that we are under a lot of pressure to ensure that we serve our customers, at a minimum amount, you know, of the cost, minimum of cost. So when we have overloaded systems, we try to do the minimum that we can, to be able to continue to serve our load reliably and safely, and maintain the systems without becoming overloaded.

Putting additional equipment out there, and typically that basically what it means is if we have a circuit that's overloaded, we put a new breaker at the station, typically put a wire down to a specific area of a circuit, break up a circuit in half or something like that and call it good, right?

Putting additional equipment out there, that would require putting communication systems, putting more monitoring equipment. So even on those projects that are currently in the pipeline, now you're talking about increasing the cost of those projects.

Once you increase the cost of those projects, now you have to take the money away from other projects that are required to continue to serve the load.

So it's, you know, even on existing projects that are under the pipeline, just because they're new projects doesn't mean that you can put the equipment for monitoring the minimum loads out there, because that's going to be an incremental cost for which we don't have the money for to do.

MS. KERR: Okay, thank you. Mr. Adamson.

MR. ADAMSON: Yeah. I just want to make a quick comment on something Kristen said. She mentioned putting together kind of a customized load penetration thing, and that sounds very appealing, something we would support.

But our near-term focus for this petition is 100 percent of minimum daytime load screen, which the lab, you know, EPRI report lists in terms of short-term solutions, and there's a lot of, you know, more can be done. But we're trying to walk before we run here.

MS. KERR: Okay, thank you. Mr. Ray.

MR. RAY: Okay. So just one comment in terms of what we've all heard earlier, in terms of the fact that collecting load data is very expensive, it's time-consuming, it takes a lot of resources.

I guess given that there is a strong signal from the solar developing community that's going out, in terms of the genuine need for getting the minimum load, have we vetted enough or had a stakeholder initiative, especially in the high penetration areas, in terms of understanding what is the cost of such load data collection, and how much does load monitoring devices would cost.

Perhaps a middle ground or compromise would be to take a tiered approach, and install the load monitoring devices in the areas where traditionally interconnection requests are much higher than other areas.

Because utilities typically have a pretty good understanding of where our higher concentration of interconnection requests that are coming in, as opposed to other areas, where developers are not that interested in building projects.

So could there be a tiered approach that could be adopted, in terms of leveling out the cost of such installations and getting the minimum load data to the solar community. So I think it's worth exploring into that world a little bit more, as opposed to being having a dismissive approach of saying that it costs too much money and there's just no need for such minimum load data. I think it requires more discussion.

MR. DAUTEL: And in fact, isn't the proposal to only require these on line sections with at least ten percent of minimum load, or I'm sorry, of peak load?

MR. ADAMSON: Yeah, that's the SEIA proposal, is that the obligation to collect minimum load data would kick in if a circuit line section, you know, hit ten percent of peak.

MR. DAUTEL: And do we have a sense for like, I know Roger you said that there's 38,000 line segments in SoCalEdison. Do you have any sense for how many of those would be impacted by a proposal like that? Or of the 5,000 that are already monitored?

MR. SALAS: Yeah. I'll answer that coming from Bhaskar. Yeah, frankly I mean you're talking about 38,000 line sections that we have.

I would say, gosh a rough guess, probably about 95 percent of projects probably don't have, and that's just a rough number, don't have the ten percent that they're looking for, but yet they're requiring us to, or also be required to provide that data, even though it's not necessary.

Because with how many applications we have at SCE, probably 1,000, you know, or something like that, you know, maybe 1,100. But we have 33,000 line sections. So you know, it's just a very enormous amount of line sections for which data doesn't exist, and a lot of work needs to be done.

The other thing that I want to point out, according to Bhaskar, is that concentrating or getting the load data for these areas with higher amount of requests. Well, that's taking into account a FERC tariff and CPUC tariff.

We have about, I would say, about 75 percent of projects are in what we refer to as transmission-constrained area, where basically out in the desert, there's no load out there, and any amount of power you put into the distribution system is going to flow back to the transmission system, and creates problems with other projects already proposing to connect to the transmission system.

So putting that information in that area really, it's not going to help, you know. So you know, if the proposal was to say well, just look at the areas of higher concentration, well that's the areas, that's the desert, okay.

So really even if you had the data it doesn't help you, because you have to go through the study process, because you have to be combined with the rest of the projects that are connecting to the 66 kV system, the 115 kV system, and those that are under CAL ISO control.

So you have to put them all together to be able to study them together. So really you don't, that's really the worst location you want to put them in.

MS. KERR: So are those locations, I don't think we've talked about it yet in this panel, but earlier today we talked about the maps that the California utilities have to put out, in addition to the reports, in the Rule 21 settlement. Would that kind of location show up on the maps?

MR. SALAS: Absolutely. We definitely on the maps we have, there are various levels, and we basically said oh, this area here, it's a transmission-constrained area. Do not, well you know, be aware when you propose projects in this area, because they're going to have to go through a study process.

We provide information as to where our load centers, where is there's no transmission problems, and we have, you know, maps that show whether you can, you know, those circuits that have high amount of -- high loads and low generation.

So that if you see a green circuit, that means that this project can potentially pass the fast track. But a minimum, if you were to use the maps to say don't, stay away from the transmission-constrained areas. So be aware that there's a transmission problem here. If you stay away from those, your minimum can go through the ISG study process, and still interconnect with them.

MS. KERR: So in putting together those maps, even that even the peak load data, it sounds like not always available by line section, are you using substation data or --

MR. SALAS: Transmission system data.

MS. KERR: Transmission system data?

MR. SALAS: Yeah. I mean basically it's all the generation that's being proposed in the distribution, subtransmission and transmission system, and then determining that there's already, you know, 115 or 220 kV problems out there, where lines need to be upgraded.

So knowing how long it takes to do those type of projects, really putting additional projects on the distribution system is problematic. So we don't -- on that level, we don't even use the distribution level. We use the transmission level.

MS. KERR: Okay. Okay, thank you.

MR. LUONG: I'd just like to clarify one more thing. So you mean that it's a transmission constraint on a transmission system, not on a distribution level?

MR. SALAS: It's both, but you know, typically, distribution issues can be resolved quickly. So if you're putting projects in a distribution, where there's no transmission problems, you'll be able to find the problems, you'll be able to mitigate them. You can go through the independent study process and still interconnect, you know, quickly.

But in those areas that have transmission problems, it's just -- you really have to be studied together with all the other projects. It wouldn't be fair, you know, to put 30 megawatts of 1.5 or 2 megawatt generator projects, and allow them to interconnect, while you have the other transmission projects being held back. So you know, that's really where the problem is.

MS. KERR: Okay, Mr. Ray.

MR. RAY: Yes. Just a quick comment on that whole question about the transmission, you know, becoming a global issue. It is true, we all understand the fact that, you know, when you've got a transmission level constraint, that that impacts every little generator that's going into that cluster.

But the reality of the fact is, I'll just use Edison as an example, is there are several transmission projects committed, because there are other large-scale solar projects going into the transmission level that has triggered those congestion, and they're being addressed by building transmission to open up those bottlenecks.

The reality of the fact is because FERC's plan approval is in place, and several transmission projects have been undertaken, I think we need to decouple those issues and take a look at the distribution system at some point, because those transmission bottlenecks are being addressed and they are going to be resolved, because several projects are already under construction.

So I think that may be the case very well today. But in the near future, those transmission bottlenecks, when they go away, we're still stuck with this whole distribution level, 15 percent minimum load screen issues, because the transmission projects are going in, and billions of dollars are being invested under FERC plan approval, to take care of those issues, because they are more pressing.

MS. KERR: Mr. Salas, do you have a reply?

MR. SALAS: Yeah, definitely. Yeah definitely. We're not saying that those projects cannot interconnect, okay. We're saying that those projects are going to fail, specifically fast tracks screens number nine and ten.

So they are not -- we're not talking about whether or not those projects interconnect. We're talking about those projects have to go through further studies, because they're failing -- they're not failing the 15 percent screen. At that point, it becomes almost irrelevant, you know.

It's a factor in the distribution, but you're going to fail nine and ten, and no matter what, you have to go through a study process.

MS. KERR: Okay. We just have a few minutes left, and I have at least one more question. But Mr. Adamson, did you have a comment?

MR. ADAMSON: Yes. I mean it's quite clear that, you know, minimum load data is just not available from a lot of utilities, and that's going to change over time.

We don't know how quickly. But I think what the issue is here is Order 2006 was essentially the 15 percent threshold, a way of estimating minimum load, and it's one that's turned out to be overly-conservative and turned out to be a market barrier to solar in the current environment.

What we're asking you to do with SEIA is to adopt a new and improved way of estimating minimum load, either providing for minimum load data or estimating. It's very clear from the panel that there's going to be a lot of estimating. It's something utilities have done, even for peak load where they don't have it.

So you know, I hope that everybody goes ahead and gets minimum load data available right away. Realistically, it's going to evolve. But what everybody can do today is they can do a much better job of estimating minimum load on a circuit than they did under the 15 percent rule.

MS. KERR: That leads me to my next question, which is what are the current concerns associated with estimating minimum load, to the extent we haven't talked about them already, and what can we do or what can utilities do to alleviate those concerns? Mr. Roughan.

MR. ROUGHAN: Yeah. There's two parts to that. I think Roger, you know, hit the nail on the head in terms of when you really get into looking at minimum load, if you don't have the raw data. You've got to do an extensive review of the customer population, you know, the fusing, the reclosers, all what you've sized things over time.

I think the dilemma with that is estimating minimum load in order to meet a very quick fast track time frame becomes very difficult in those short time lines, because we also have to recognize as we move forward to get actual minimum load data, those decisions are made by every state regulatory body to approve those investments or not.

We just need to recognize that from that perspective, it's going to happen over time, but it will end up being, you know, that particular state that authorized that particular distribution, getting utility approval to spend money in this way or that way, right?

That's where, that's how you're going to fund it, if the solar development community isn't going to fund it. So that's where we have to really understand it will happen. So estimating minimum load is still, and as Kevin said, I think clearly when you have the pre-application report, because we do those as well in the northeast, which are very effective, you can provide it.

If you don't have it, and they roll into the other studies, then you can go ahead and try to get it, because we do come up with -- we do estimate the minimum load when we're doing the impact study, so we can understand do we need to be careful of islanding and that sort of thing.

MS. KERR: Ms. Nicole.

MS. NICOLE: So I would just make the point that we are talking about minimum daytime. So that's kind of the context of the conversation that we're talking about, and also not get away from the idea that it's also in the context of line segment versus circuit or feeder level or transformer level.

You know, it seems -- from my understanding, it seems that the minimum load data is available at, you know, for folks who have SCADA systems or other sort of digital applications. They can easily get that data. So it's not necessarily that that's a prohibition to moving forward.

However, what I like to think about is kind of the difference between when we mentioned daytime minimum load in the paper, it's kind of in your mind separating out the difference between the interconnection screen and a short-term solution for improving the screening process, versus solutions for integration of solar.

It's two, in my mind, it's two very different topics. So right now the 15 percent is an estimation, and so can we improve upon that with, you know, as Mike Sheehan said, with validation of measurements in the field, or more transparency on data that's already being collected, or potentially collecting more data?

I think those are all potential options, but they should be focused on the conversation of addressing the problem of the accuracy or, you know, usefulness of that particular fast track screen.

When you talk about integration of solar, you know, which we do every day at EPRI, it's a matter of understanding the complexity of the system, and frankly what we're looking at is it's not so much a load data or megawatt, PV megawatt data.

You're looking at a host of different characteristics and the interaction of those characteristics, how load changes over time or what estimates you're making, what data you have available.

So what we would like to do is get away from sort of 15 percent or 30 percent or 100 percent, and try to talk more broadly about what we can do on the integration side. That would then sort of feed some of the interconnection policies, in a way that everybody's happy with.

MS. KERR: And Mr. Fox.

MR. FOX: Thank you, Leslie. I just want to take a moment to echo what Tim said, because I think he really kind of got at the nut of the issue here. The issue really in my mind is how long does it take to estimate the minimum load.

I haven't really heard anybody speak forcefully against relevant, minimum load being a relevant criteria in the interconnection process. Roger talked about the fact that if they were doing an interconnection study, a system impact study, they would take a look at minimum load, and they would have additional time, and certainly, you know, the additional funding through interconnection study costs, to be able to take a look at minimum load.

I think the issue really here with the

supplemental review is, because the supplemental review I think this got lost a little bit earlier on the first panel, is you know, the initial review screens are kind of a thumbs up/thumbs down sort of approach.

What California did with supplemental review really operates very differently. It allows a lot more engineering discretion and judgment to be involved with the application of reliability, safety, power quality screens. Also, one of those considerations, then, is minimum load criteria.

So to the extent that is a relevant consideration in the process, in California is was felt that the exercise of the engineering judgment around reliability, power quality and safety sort of issues could be coupled with the calculation or estimation of the minimum load, so you could do a sort of quick, second look for systems that failed initial review, and say within 20 business days and with a $2,500 fee, yes, this system can pass without additional study, or no, it needs additional study.

But there's a fair amount of discretion there to apply engineering judgment, so we can avoid the sort of, you know, bad case scenarios that a lot of people brought up on the first panel. You know, I've talked to a number of utilities about this, and a number of them have echoed the belief that they don't necessarily want every single project to go to study either.

So I think really at the core, what we're talking about here is is there some subset of projects that may fail the initial review screens, that don't necessarily require full study? Because if there is, then it makes sense for everybody involved to pull those out, and create a process that allows them to be addressed quickly, and at a reasonable cost, without a full study being required.

MS. KERR: Well with that, we're going to end this panel. Thank you very much for a good discussion, and we will be back in 15 minutes. Again, for folks who are leaving, I would just like to remind you that we are taking written comments for 30 days on the issues brought up in this technical conference. Thank you.

(Whereupon, a recess was taken.)

MS. KERR: All right, welcome back to the last panel. Our last panel of the day is on the "Review of Upgrades" required for interconnection.

Our panelists include Jim Torpey from SunPower Corporation, on behalf of SEIA; Rick Gilliam from The Vote Solar Initiative; Dan Adamson from SEIA; Roger Salas from Southern California Edison; and Steve Steffel from Atlantic City Electric; and Steven Herling from PJM.

I would like to invite our first panelist, Jim Torpey, to give his opening statement.

MR. TORPEY: Thank you, Leslie, and thanks to FERC staff for convening this discussion on barriers to interconnecting solar and distributed generation.

My name is Jim Torpey. I am the Director of Market Development at SunPower. SunPower is a manufacturer and developer of solar-based projects in California, our headquarters in California.

A couple of things that are relevant. For one, I have worked for 20 years of my career for a public utility, and I will just say that I really respect all the things, and the difficulties and the problems that you've heard about today. And I also have seen the tremendous ingenuity and ability to solve problems at the same utility engineering groups, and I am sure that a lot of these things that we've talked about as we work together can be solved.

SunPower has either interconnected or is in the process of interconnecting about 1200 megawatts. So we do have some experience and some of the things that I'll be talking about are based on that experience.

We've heard today appeals to work together with utilities to improve interconnection and reduce costs, and we are certainly very interested in doing that. And I think what I am going to talk about and what we'll talk about on this panel is at least our attempt to start to work that out, work out one process for how to do that.

Reducing costs is very important to us, both from the standpoint of reducing time and effort that the utilities have to do in order to review interconnection requests, and then also in terms of the time and money costs of interconnecting and making sure that those are appropriate for meeting the needs of the grid.

I think one of the things, when somebody asked on an earlier panel what are some of the costs involved in these interconnection studies, the thing that is really important to understand from the aspect of solar development is time is money. And it's something that if you put a project into what we consider to be sort of a black hole of an interconnection request and don't know when it's going to come out, an answer, or how much that is going to cost, it is really something that makes a project very difficult to finance. And you're basically really making that project a lot more, not only difficult to finance but more expensive.

And so I think it is in everyone's interest to try to make that process work a lot better.

What we are seeing is that there is little transparency--and this is again from the perspective of a solar developer. We are seeing little transparency regarding each public utility and/or transmission owner's technical requirements for interconnection.

In practice, each is different and each may change over time. From our perspective again, once we submit a project oftentimes it seems like it falls into a black hole. You don't know what's happening. You don't know where it's going. You don't know how much it's going to cost.

And what happens is that we also see sometimes some of the requirements appear arbitrary and discriminatory, and that individual developers are sometimes asked to take on costs for technical solutions that appear to be either excessive or unnecessary as related to a specific project.

I think later in the panel Rick may give you some more specific examples about that. But in any case, there's really no effective process in place today for adjudicating these disputes concerning reasonable and alternative solutions for maintaining distribution reliability and safety.

And again, it is not our intention to get around anything that has a safety or a reliability impact. But sometimes there are different alternative solutions and ways to do it a lot better than--or at least from our opinion, there should be some process for figuring that out.

So what we are really talking about is presenting an approach that's an improvement to transparency and also to process.

So the first step one, we need to know what the process is for each utility. And sometimes you've heard a lot from the utilities today, but not every utility is as completely upfront and able to work as well as some of the utilities you've heard today. So we are really talking about a process that is required across the board in many cases.

We are really looking to require utilities to publish what their requirements for such items as voltage control standards, when a transfer trip is required, et cetera, et cetera, a lot of technical requirements. Sometimes we don't even know what they are until after the fact. We would like to see those up front. As well as a time frame for which they say we can develop a project under X amount of time, and these are the time frames. And then we should have the right to challenge those if they are unreasonable.

The second thing is to define what some alternatives are in case there is a dispute over what the best solution is. So cases where the developer believes that proposed upgrade requirements are unreasonable and not supported by the facts, developers should have the right to commission at their own expense a professional engineering report outlining alternative solutions to identified issues.

And then we can go through a process--this is one process that we're suggesting, but we're not saying this has to be prescriptive. But in any case, a utility could either accept the developer's report, or they could say, no, we don't really accept your report. And so what we would do is go to a third party.

You'd have an independent third party who would then look to present the facts, by reviewing both the utility report and also the report of the individual developer, and then come up with an opinion. That opinion would then be--although the final decision would remain with the public utility, the utility will be expected to give substantial weight to the findings and recommendation of the third party expert when making its final interconnection decision.

In the event the utility does not accept the expert findings and recommendations, it must provide the applicant a fulsome explanation of the factual basis for not accepting the third-party recommendation.

I know there was a question about whether it would be a viable alternative to have a comment section, as is done in the large generator interconnection procedure. In conversations with developers familiar with the practices of public utilities and the LGIP procedures, the general consensus is that the opportunity to provide comments is somewhat perfunctory because the public utility is under no obligation to seriously consider the alternatives being presented by the developer's engineering consultant.

By adding an objective third-party expert's input, the expectation is that there will be a higher standard established for considering and incorporating the objective engineering input.

Thank you, very much.

MS. KERR: Thank you, Mr. Torpey. And now let me move to Mr. Gilliam.

MR. GILLIAM: Thank you, Leslie.

My name is Rick Gilliam. Just by way of background, I spent a number of years here on the FERC staff, actually, at the start of my career. I worked for a utility for a dozen years. And then went to work for a competitor of Jim's here, SunEdison, and worked there for a number of years. And now I'm with Vote Solar.

Vote Solar is a nonprofit 501(c)(3) organization that advocates for positive solar policies to bring solar into the mainstream across the United States.

I appreciate the opportunity to speak today, and the comments I have will address the interconnection standards first established as part of Order 2006.

As you know, these have been used by many states as a model to develop similar interconnection standards for connections of small generation to the distribution grid. As such, these rules have set effectively a minimum standards for SGIP on the distribution grids.

As we have heard earlier today, the lack of consistency, the costly and lengthy process, is a problem for solar developers. Our goal in making these comments today is to help promote a clear and predictable path to interconnection for distributed generation.

In my experience, for projects that do not pass the Fast Track screens, utility facility studies have found a diverse set of assets and costs required for the interconnection. In addition to expected and quite normal costs such as reconductoring, transformer upgrades, and so forth, upgrade requirements have been imposed that include exorbitant and sometimes surprising costs of things like extensive telemetry equipment, life-of-asset O&M costs as part of the upgrade, and income taxes included in these estimates.

It's not at all clear that the assets identified in these upgrade requirements are the minimum required to resolve the concerns and inclusions of the system impact study. And we all need to remember that these costs, one way or another, ultimately will be paid for by the utility ratepayer.

Additionally, some transmission providers--and I use that interchangeably with IOUs--have played a type of Price Is Right game with the feasibility study in which a quick turnaround is offered if the developer accepts a facility's estimate with little supporting documentation or, Door Number Two, wait longer for the unknown system impact and facility studies which may result in higher costs.

While such an offer may be made in full good faith, it offers the potential for gaming, particularly when solar developers operating in a highly competitive marketplace are anxious to move projects along as quickly as is feasible.

This risk is compounded by the serious information imbalance between the utility and the project developer. The developer has little upon which to base an informed decision. The preapplication report that's been discussed several times earlier today in Rule 21 we think is a good step forward in that regard.

Overall, in our view there's insufficient transparency and accountability in the interconnection standards. Order 2006 did provide for some relief in Section 3.5.4, but unfortunately the wording of the section leaves the utility as the party with the ultimate decisionmaking authority. And as Jim said, it provides little motivation for the developer to challenge those findings if there isn't an opportunity for either a third-party review or ultimately an arbiter such as a public utility commission.

The supplemental notice that the FERC issued asked for us to address a few additional questions. So just to cut to the chase:

In our view, an independent third-party review of upgrade requirements would help generation developers to have confidence in the determination of upgrade requirements, but only if there's an opportunity for backstop regulatory oversight.

It is unclear whether the written comments contemplated in the second question, the LGIP, would be made to the transmission provider or to a regulatory body. If it's to the transmission provider, I agree with Jim that there is not much motivation on behalf of the developer to follow that path if the transmission provider is the ultimate decision maker.

Indeed, we believe the feasibility study itself should be subject to the same opportunity for third-party review of potential adverse system impacts with a right to appeal to the regulatory body as the final arbiter.

You asked for some down sides. I can get into that in a few moments. The cost of engaging a credible engineering firm to review potential system impacts and upgrade requirements could be a challenge, in that the firms that are out there often are retained by utilities for work, and there may be a conflict of interest.

And the size of the projects that generation developers in the solar space typically do are considerably smaller than other opportunities that utilities may be able to offer engineering firms. So there may be some reluctance on the part of such firms to engage in that process.

Having said that, we think it is still important to have that opportunity to engage a third party.

Finally, I would like to ask the FERC to continue its original plan to review these interconnection standards on a periodic basis so that we can stay current with the fast-changing technologies.

Thank you.

MS. KERR: Thank you. And Mr. Adamson.

MR. ADAMSON: Thanks. So we're talking upgrades. I think it's good to at least spend some time on it, because we have spent so much time on minimum load and Fast Track--which not to discount that; I think they're very important--but this upgrade issue is important.

Let me just stipulate up front that, notwithstanding the various anecdotes that we've brought to your attention, that I think the recommendations that utility engineers make on these sort of upgrades are offered, you know, based on their expertise, and they're offered in good faith. I think they're trying to do their job, which is not an easy job, and part of it is keeping the lights on.

But I will also stipulate that utilities are not infallible. They have not discovered truth. And so sometimes they make a mistake in terms of an excessive upgrade requirement. And I think it's really expecting a lot of the utility to be an impartial arbiter over a situation where its own self-interest is at stake. And this is a familiar situation for FERC, obviously, you know, in your quest to have J&R transmission access.

So I mean there is a little bit of a conflict of interest. You know, generally the unit to be interconnected is competing against a utility in the wholesale market. And I also think, you know, having also done a lot of work for utilities and spent time with utility clients in a prior life, you know, the addition of DG to a circuit does make a utility system engineer's life more complicated. You know, that's just a fact.

And so it's hard for the utilities to always come up with what we would view as a reasonable and cost-effective upgrade solution. And so we think the remedy is to bring in a third party, and SEIA's petition proposes that at the request and cost of the applicant, that a third-party expert reviewer would be brought in; but that the utility would still, as it must be, be the final decision maker. I feel that very strongly that, you know, utilities are accountable for reliability. And so in the end it is their decision. But, that they would be required to give due weight to the report of the independent expert.

And I think just bringing in somebody who is impartial, or at least a third-party expert, could really help solve this problem. You know, SEIA is not wedded to a particular process, but we are wedded to the notion of third-party review and some type of orderly process. Because the upgrade issue is right up there with Fast Track in terms of the concerns that our members have.

And that's all. I'll finish up in three minutes on that one.

MS. KERR: All right. And Mr. Salas.

MR. SALAS: I would like to again thank the Commission for the opportunity to participate in today's conference, and to offer SCE's perspective on SEIA's proposal that the SGIP be modified to provide for a third-party expert review of upgrades identified as a requirement for an interconnection.

SEIA's proposal requires transmission owners such as SEC to give substantial weight to third-party experts' findings and recommendations for the identified upgrades and to provide a fulsome explanation of the factual basis for rejecting the expert's recommendations.

It is SCE's position that qualified third-party experts can provide meaningful input during the interconnection process. That being said, we respectfully oppose SEIA's proposal because it will not facilitate meaningful dialogue between the utility and the third-party expert, but will instead likely create additional delays and disputes during the interconnection process.

During my prior panel discussion, I explained that the SGIP is working as intended in SCE's service territory in that it has not unduly discriminated against solar developers. What I would like to expand on upon here is how the current SGIP already allows for meaningful dialogue between the utility and the interconnection customer with respect to upgrade requirements.

As indicated previously, we have studied nearly 600 interconnection requests in the last three years under the SGIP. In our experience, the process works well--but only when the third-party expert is familiar with typical distribution system standards and practices.

Under the current process, applicants are encouraged to bring, and often do bring, engineering experts to the study results' meetings to discuss the upgrade requirements that SCE identified during the study process. During these meetings, we sometimes hear suggestions regarding modifications to proposed distribution system upgrades.

We are not averse to implementing the suggestions as long as the proposed changes meet SCE standards in terms of design, construction, operation, and maintenance, as those standards have been reviewed and approved by SCE experts in these respective areas.

This is crucial as distribution upgrades and interconnection considerations must comply with our company's standards to ensure safe and reliable operation of our system for our employees and customers.

Nonstandard equipment design or construction may make hazardous safety conditions, problems operating the system, or longer delay times during a service restoration during an emergency.

We explain our comments on SEIA's proposal that we believe that an outside expert can provide a meaningful input during the interconnection process, provided that the expert is familiar with our distribution system, and in fact we have had instances where applicants' expert engineers were familiar with our systems and they suggested appropriate changes that actually did reduce their costs significantly.

We also believe that the applicant who hires such experts will benefit from involving the expert at the start of the application process, as opposed to waiting until after the studies have been completed and the resources have been already submitted--provided to the applicant.

Waiting until the studies are provided will only serve to further delay the process and potentially increase the cost to the applicant.

In conclusion, we respectfully submit that the SCIP works well for all applicants who take the time to hire a third-party expert that is familiar with the distribution system standards and practices. We hope that the perspective that we have provided here today is helpful to the Commission and some of the participants and we look forward to further discussion.

That's it.

MS. KERR: Thank you. Mr. Steffel.

MR. STEFFEL: Thank you. Steve Steffel representing PEPCO Holdings, Inc., and the three utilities we have, Atlantic City Electric, Delmarva Power & Light, and PEPCO.

The first thing I wanted to mention, just to start with studies and the upgrades, looking back in 2011 we had about 1700 applications, 76 megawatts added to the system, and there were about 35 studies.

Of the 35 studies, a number of them did not proceed to build. So you can see that with that small framework there's not tons of projects that needed upgrades, but of those 35.

The first thing we think about is process. We mentioned that. We've had public forums that would explain to developers the process both on the NEM side and the wholesale side. And on the wholesale side, they run through our ISO, PJM, and Steve Herling will probably touch on some of that. It's a very structured process, including review, reviewing the transmission impacts and so on and so forth.

And we follow that very carefully. We are in a sense sub to them. They are the project manager on those wholesale projects.

The next thing that is important that was mentioned is criteria. And it is true, we have had to develop a lot of criteria for DERs being added into the system. And anything that has been--or is geared to the understanding of the developer, we have put into our public documents. We have some interconnection documents that are on websites. And they're updated yearly, every couple of years. And so we probably have some more things that we've put in.

We actually are putting them right in the studies, some of the very salient points, so that they understand what our criteria is and why we would require an upgrade, and so on. And these are very valid points and we're trying to address those kinds of things right up front so we don't run into issues there.

Currently we've done most of our studies with third parties. And we do make those studies available when they're finished to any developer that wishes to have them, all practically 50 pages of them or so. And we've set down and discussed with all of the projects that have needed upgrades, and we haven't had any that have required, you know, review by a third party yet. I mean, I understand some of the concerns. But we've been able to work through that.

One of the things we're working on in-house, and we've mentioned it, is that we are working on our own time series load flow program with an automated study tool so we can save developers both time and cost. And I think that will be a significant benefit to them.

Now some concerns with third-party reviews. Each utility has its own planning and operating criteria and construction standards based on national and state standards, and best industry practices. And a third party, whoever is reviewing the results of a study, would need to follow those when assessing the recommended upgrades that were put together as a result of the results of the study.

Now it's going to add time and cost to studies. There will be added effort by the utility to explain the study results, study criteria, construction standards, et cetera, and to provide the needed information for the third-party to do the review.

We haven't had to have that to this point. We've had good discussions, and talked with our developers who are putting things in, and anything that they suggested, if we could accommodate them, or if there were options, we made those available.

But the main thing was to build the system to the standards and criteria that we had laid out as a utility. And we do that whether it's an internal project or an external project. We don't build them differently.

So my only concern would be it does add time. It does add cost. All those things have to be explained. And it does open up the possibility for some maybe contention, or whatever, but I don't see it as a major issue because we haven't had too many--haven't had any issues of that nature up to this point.

MS. KERR: Okay. Thank you. And Mr. Herling.

MR. HERLING: Good afternoon.

My comments are related to the projects as they proceed through our interconnection process, specifically to participate in either the PJM energy market or the capacity market, or both for that matter. This is a relatively small slice of the projects that are connecting in PJM. We have a lot--a very large number of net energy metering projects, in the thousands, or tens of thousands that PJM does not get involved in. We have processed about 600 projects through our interconnection queue.

At this point I think we have about 3,100 megawatts that are either in service or are currently under construction. So from a megawatt perspective, it's a fairly large number. But from a project perspective, I think in New Jersey alone we have had 14,000 requests under net energy metering, and in all of PJM we've only had about 600 requests to get into our markets.

Now procedurally we use the same process that we use for large generators: feasibility study, system impact study, facilities study, and ultimately execution of a Wholesale Market Participant Agreement, or an Interconnection Service Agreement.

The difference really is we have screening tools that we use to determine whether or not there will be network impacts that need to be considered--meaning higher voltage, 100 kV and above impacts.

The solar projects that we look at are typically in the range of about a half a megawatt up to 20 megawatts. So by and large we have seen very few impacts on the higher voltage transmission, and when that is the case we then move the project to the transmission owner for a look at the distribution and the subtransmission voltage levels--12 kV, 34.5 kV, and such.

The vast bulk of the analysis for those projects has to be done by the distribution owner. We just don't have the involvement in those facilities. The bottom line is, we still manage the process with the transmission owner and the interconnection customer. We still facilitate all of the meetings around the different study results. In many cases, the interconnection customer works with a consultant throughout the process. So we facilitate meetings. We take comments at each stage of the process, and we'll factor in their suggestions into any upgrades or results that perhaps we need to take a different look at.

The bottom line is, I provided in my materials a map. There is a significant number of projects, if you look at the geographical areas. So we still do have to manage the rights of the different projects since they are trying to connect back into our markets. So the study process still has to follow the timeliness that are dictated in the PJM Tariff in terms of, you know, the completion of the studies, and the amount of time that the developers have to review the results with PJM, with the transmission owner and their consultants, and get responses back to us so that they can then move on to the next stage.

At this point, we have had, you know, as I said, a fair number of the interconnection customers using this meeting process to review the study results, to review the upgrades with their consultants. I'm not sure that we need to have a third party completely separate from the customer and their consultants and PJM and the transmission owners. It seems so far that we've been able to get through the review of the upgrades and the projects that are moving forward have been able to identify the required upgrades and move on.

We have so far had about a 65 percent dropout rate among solar projects. The dropout rate in the big queue is probably closer to 88 percent. But that could just be because the solar projects are newer to the queue. We have still a couple of thousand megawatts of projects under study. So by the time that wave comes through, it may creep up a little bit.

The bottom line at this point, I think the process is working reasonably well. We are managing to keep it reasonably close to the tariff timeliness that are specified. And we have gotten a fair number of projects connected to the system.

Our experience is improving, as are our transmission owners, in terms of the types of analyses that they have to perform. And I think generally it's working pretty well at this point.

Thank you.

MS. KERR: Okay. Thank you. I guess the first question I have is: How would the independence of the third-party be assured? Whoever is interested in answering that?

MR. ADAMSON: Could you repeat the question?

MS. KERR: How would the independence of the third-party reviewer be assured?

MR. ADAMSON: Well, I think--

MR. DAUTEL: I think, just for some background, we got some comments that there was some question about whether the independence could be assumed in these cases.

MR. ADAMSON: You know, all I can speak to you is to what SEIA specifically proposed, and we proposed that essentially that you as a developer be able to bring in what you considered to be an independent third-party reviewer.

We didn't--basically, they are able to come in and hire their own experts. So I don't think there's necessarily some type of litmus test. But obviously if you pick somebody who is viewed as, you know, biased, that expert is not going to help you nearly as much as somebody who is viewed as playing it straight and somebody who is respected by both sides of the equation.

But we weren't thinking that there would be some kind of a specific standard. I can't speak--Jim offered some other thoughts, but--

MR. TORPEY: Yes. So this is speaking only for SunPower, not for SEIA, because this is not a SEIA petition, but I would envision something where you would have something like when you choose an arbitrator in a land dispute, or an appraisal dispute, where you have different parties suggesting people. And then you pick from a common group.

In other words, I would see something that this expert would be somebody who would be approved by the utility and approved by the developer. And the idea would be to have a sort of a cadre of people who you would choose from, just as you do appraisal firms. And again, it would be important I believe from the utility perspective to have that person vetted so that they would understand something about the nuances of the system, et cetera, so that you wouldn't just be, you know, kind of plucking people out of the air; you would be plucking people, or sort of engaging people who have more experience and at the same time would be recognizing from the utility--from the developer side some of the nuances, or some of the alternative ways to come up with solutions that might be a little more cost effective.

MS. KERR: Dan?

MR. ADAMSON: Yes, you know, I also said I think we're flexible on this issue. So I think what Jim is talking about falls within the ambit of the kind of idea that SEIA is supporting. We just want to get some type of third-party expertise involved. There's different ways to do it.

MR. QUINN: Could I just ask a follow-up? Can the ISO or the RTO, if there is one in the area, serve that purpose of independence? What Mr. Herling was talking about sounded a little bit like you were facilitating meetings between the developer company and the interconnection customer. Do you feel like you were applying engineering judgment in facilitating those meetings? Or were you mostly there as a facilitator in kind of this arbiter role?

MR. HERLING: Our ability to do that is fairly limited. We do facilitate those meetings. At higher transmission voltage levels I think we have a lot of expertise that we can apply to discussion of what upgrades may be required. But once you get down into the distribution system, it would be probably better to get firms that have that expertise specifically. So I don't think we could provide that level of expertise to provide that function.

MS. KERR: Mr. Torpey?

MR. TORPEY: I just want to be clear about one thing. First of all, what I'm not suggesting is that you don't have a third-party person engaged at all in the conversation from the very beginning.

I think any solar developer who has got any concept of how to get things done will be sitting down with the utility and PJM as one of the first things they do, with an independent consultant--you know, with their own third-party, or it could be someone from within the company--but engineering expertise to sit down and talk from the very beginning on how to put together the interconnection study.

So it's not let's wait to the end and then kind of make this process--kind of force this process. So that's the first thing.

And the second thing is this need for a third-party person, I think as Steve said and other people have said, many times this works very well and it's not necessary to do this. This would be sort of an extraordinary circumstance where there was a real dispute.

And what we're talking about is a lot of these costs being borne by the developer. So no developer is going to go through this whole process unless there's really something significant at stake. So this is not something that would be the norm. This is something that would be more, in my opinion at least, more an extraordinary or an unusual event.

But at least it would give a process, and it would provide a mechanism for this kind of third-party opinion to be codified and provide more of a record for a real codification of what the dispute might be.

MS. KERR: Mr. Herling.

MR. HERLING: Yes, I just--I agree with Jim's comment about the importance of having the developer bring expertise with them, consultants or staff, whichever, all the way through the process.

And honestly I think that will serve in most cases to bring the same value that a third party would bring. We have consultants all the time challenging the upgrades that are identified, and suggesting alternatives, and we'll ensure that they go back and look at those and we'll determine whether it makes sense or not.

To have a truly independent third party, we don't have any experience with that so much in the interconnection process, but in our regional transmission expansion planning process we do now accept proposals from independent, nonencumbent transmission owners that they would like to develop in PJM.

We will hire firms, siting/engineering firms, construction firms, to do estimating and to evaluate the risks associated with siting and regulatory, et cetera, for those projects to kind of balance the estimates that the parties are providing to us.

We're using the same firms that our transmission owners are using, and that the nonencumbent developers are using. So what we typically do is have a bunch of them under contract, and in a given geographical area we try to get somebody who is not already working for the nonencumbent or for the transmission owners. And it's a challenge. And let's face it, they're not making nearly as much money working for PJM as they will eventually for, you know, the successful proposer of one of these projects.

So it is a challenge to find a true independent, and they often have to ensure that they're working with a crew where they can put a wall up between other parts of their business.

MS. KERR: Okay. Thank you. Mr. Salas.

MR. SALAS: Yes. I would like to address very quickly the--you know, as I stated before, we have the examples in the current process where applicants bring experts. I can think of at least three off the top of my head where the cost of interconnection is significantly high, so we're not talking about your simple little interconnections, but distribution upgrades, long-line extensions. And under the current process we already have the ability and the applicants have that ability to bring experts to basically challenge or provide for alternative solutions.

And under those types of projects that I'm thinking about, I mean we are looking at alternative ways to present the substitution upgrade, or alternative ways to do a significant line upgrade which saves the applicants millions of dollars.

So that process is already in place. And I just find it difficult that we're talking about adding an additional component that can't really not--I'm not sure it's really going to serve the needs of, you know, SEIA is proposing.

MS. KERR: Thank you. I guess I would like a little more information on how the proposal is different from the current provisions in the SGIP, if one of the first three panelists would address that?

MR. ADAMSON: In one respect, it's diff--at least the SEIA proposal, not the Torpey SunPower SEIA proposal--it just says that the utility must give due weight, or substantial weight to the conclusions of the expert. So that is a significant difference from the status quo.

MS. KERR: Okay. Mr. Gilliam?

MR. GILLIAM: I talked about actually regulatory oversight. I think Jim framed it as essentially what we used to call a "technical master" on the engineering side.

This is not a pervasive problem, but there is an issue that has come up a number of times with my former company, and my sense was that--and with a lot of regulatory experience--over time when there's an opportunity for review of assumptions that are made, review of costs that seem unusual or in some cases maybe exorbitant, over time the regulatory process results in a better, narrow, defined set of costs and cost elements.

And I don't think that opportunity is captured in the SGIP today. There is a dispute resolution process in Section 4, which of course is related to transmission providers because it relates to the FERC. But in terms of setting an example for state standards, in my view some additional oversight is needed whether it's a third-party independent arbiter such as a technical master, an engineering master that would be the final decision maker, or an opportunity to actually take the dispute to the state agency.

And I realize that that's not your purview, but that's something that we see as needed. Thank you.

MS. KERR: Okay.

(Pause.)

I'm just taking a minute to look at my notes. I guess, are there other options than what's been talked about here? The LGIP provisions seem to be not so popular with the panelists. Are there other provisions that you've thought about that should be considered?

(No response.)

MS. KERR: Seeing none, I do have a follow-up-- oh, I'm sorry, Mr. Torpey, go ahead.

MR. TORPEY: This is not quite to the point, but I think in terms of what you heard, there are a number of utilities and ISOs who essentially are establishing best practices, and being very inclusive in their processes of welcoming developers to bring in technical people, et cetera, publishing their timeliness so it's very transparent what those timeliness are, and when we can expect information back.

But unfortunately our experience has been that that's not true of everybody. So essentially when you say what else? What are our other alternatives? The alternatives that would be very helpful, if there was a requirement that everybody did what Steve is talking about doing in terms of making their requirements, their technical requirements, transparent and so everyone would know what they are. At the same time, the timeliness and when people can be expected to get answers and get studies back, and the process that they should go through in order to make sure that that moves sufficiently. That would be very helpful, and I think a lot of the difficulties that sort of people are sensing as developers with the process would really be addressed by essentially make sure those best practices are done throughout the country.

MS. KERR: Okay. So just to follow up, you're talking about what Mr. Steffel talked about in his opening, the different practices?

MR. TORPEY: Yes, the criteria that's established, and what are those criteria, and how have they dealt with these situations in the past. And, you know, when would they require something like a transfer trip, or some kind of the technical requirements; that different utilities vary on. So it's not that every utility--I'm not suggesting that every utility would have to adapt--adopt the same set of standards. But what I am saying is that, whatever those standards are, they should be published and everybody should know what they are so a developer knows what they have to address beforehand and doesn't have to wait three months to hear it.

And again, not everybody is doing that. But there are some utilities that tend to do that. And that's the sense sometimes that we put development interconnection proposals in and it ends up being a black hole, and no one knows what is happening to it. And maybe it comes back six months, and they say you didn't do X, Y, Z, and if we would of known it beforehand, that wouldn't have been an issue.

So it's a matter of transparency, and it's a matter of knowing, you know, what the timeliness are for the development process.

MS. KERR: Okay. So we have talked about this some, that revising, or allowing for more third-party review of upgrades would add cost and time to the interconnection process. And I guess I want to get a feel for what we think those timeliness would be.

What would be acceptable? If anyone would like to address that? Mr. Adamson?

MR. ADAMSON: Well I think as developer you are only going to resort to the third-party process, or expert, if there's a lot of money on the table.

I mean, if somebody is saying--the utility is saying you've got to replace that transformer or that substation, or something, you know, that cost $1 million, you know, you may save you and your company and your customers quite a bit of money by spending some money on an expert. So I think it just depends.

And you might get through your situation quicker, too. I mean, you know, you wouldn't want to--that's what Jim was talking about earlier. I mean, this is not something you would just kind of do routinely; you'd be doing it if you were in a crisis situation with a utility that, for whatever reason, you felt was being intransigent.

MS. KERR: Okay. Mr. Gilliam?

MR. GILLIAM: I just want to make sure we're differentiating between the different types of third-parties here. I think there's the third-party that would be in a sense the final arbiter of an engineering dispute. The other type of third-party that at least I've referenced a couple of times is one that is retained by the developer to review the interconnection feasibility study, system impact study, and so forth, and that might create that dispute to begin with.

In some cases, while it would be great to have--and Dan is right, that there's a cost issue here--if you have a project that's relatively small, on the order of a couple of megawatts, it's hard to know when the right time is to bring in a third-party engineering expert until you see either some initial indication of the concerns of the utility, the potential upgrade requirements, and in relation to the cost of the project if it seems out of line, so to speak, then that's when the developer may want to either bring in a third-party engineer just to hire for itself, for its own edification, or to cancel the project. And that's usually the point in time that that decision is made.

MS. KERR: Okay. Mr. Herling?

MR. HERLING: I think probably the only thing I can add, my concern would be we get a lot of projects in very close electrical proximity to each other, and they all have pending rights with respect to our marketplace.

So if we're talking about some form of an arbitrator, you know, at the end of the day when you have a dispute that you can't resolve otherwise, whatever we do we have to be able to do it quickly so that the project that has the issue is not holding up, you know, a handful of projects behind them in the queue who may be anxious to move forward with their projects as well.

It would concern me to bring someone completely new to the process in at the tail end and have to go through months of getting them up to speed, and some form of hearing, so that they can then pass judgment on the results that have been developed. And then we have to go back and, you know, provide some weighting to those results and determine whether or not a different result is justified.

Everybody behind that position in the queue is going to be impacted adversely.

MS. KERR: Mr. Salas?

MR. SALAS: Yes. I just wanted to re-emphasize again, and perhaps it is that it's a practice of Southern California Edison, where we already provide that ability. Perhaps other parts of the country don't do that, but at SCE you can bring a third-party and talk about substation problems, and talk about alternatives, and talk about different ways to mitigate the problem.

So adding additional steps in the process, as Steven indicated, can potentially put you in a situation where you are waiting for this third-party expert to make a decision. In the meantime, you have other projects that are in back that are waiting for this decision to be made.

So there's probably, you know, for the amount of projects that I have seen in the last three years that have this potential condition that could be resolved by already having the language in the tariff, it seems to me that adding this additional language, or additional provision can actually provide additional delays that may affect a lot of other, more projects than actually providing the benefit that really is already there, you know, as part of the process itself.

MS. KERR: Okay. To come back to the LGIP comment process, I guess I would like to address it to the utilities. We heard from the solar panelists. Does that process, if you're familiar with it, provide meaningful input? Or do you have any other comments on that process? Mr. Herling?

MR. HERLING: YOu know, I think there's plenty of opportunity in that process for review and input, and many of our developers come, again, with consultants and have over the years offered all sorts of alternative solutions to the ones that we have developed between PJM staff and our transmission owners.

So I think that process has worked very well. The application of the same process to the smaller projects, the primary shift is that the upgrades are now down on the distribution system. So my staff are certainly involved, but the expertise that we can bring to bear is a slightly different focus there.

We don't have as much expertise in distribution as we do in transmission.

MS. KERR: Okay. Thank you. Mr. Salas?

MR. SALAS: Yes. As I stated, you know, the current process works. But now adding this language that's going to apply to all the projects, and now you have to wait 30 business days after we provide the study, and then we have to wait 30 business days for the applicants to provide comments, it really is going to create a delay on all the projects.

By trying to help a few projects here and there that have those problems, you are going to create a delay on all the projects. Because now you have additional language there that we need to comply with.

Again, going back to the fact that we already have the process in place that addresses the condition itself, the problem, and I don't think you need additional times to actually add additional delay.

MS. KERR: Okay. Thank you. Mr. Gilliam?

MR. GILLIAM: Yes, I think I could just say as a practical matter, we are not looking to delay the process at all. Any delay adds cost, and for solar developers it makes a project much more difficult to finance. So I think the narrower thing we've been discussing outside of the LGIP process is the potential for an engineering master, which potentially could add some delay to some limited number of projects. But I think all of us have an interest in working together to keep those delays to an absolute minimum.

MS. KERR: Okay. Mr. Steffel?

MR. STEFFEL: Most developers come to us with the experts that are doing various types of electrical engineering work for them. So it would seem to me that most times those experts that they have as part of their team can act as that commentator for them, whether they feel there's something out of line with what the utility is requiring.

And then they can already provide that feedback. And they are normally on the calls that we have when we share results. We have meetings at the company with them when things are starting to move ahead. So there's plenty of dialogue there.

I'm not sure what another engineering party would bring to the, you know, benefit the whole project.

MS. KERR: Okay. Thank you. I don't have any other questions. Does any of the staff, or do any of the panelists want to say anything to wrap up?

(No response.)

MS. KERR: Okay. Well I would like to thank everyone who provided their input today. I know some of you travelled a long way. We really appreciate it.

We have heard a lot of discussion about how small generator interconnection is increasing in both the number of applications and in the amount of generation. We have also heard a lot about how the existing small generator interconnection procedures and agreements could be improved. Some of the suggestions have included creating more transparency in the supplemental review process, and providing developers with information to clarify siting decisions.

Some panelists have suggested more time and opportunity for current processes to address issues, while others state a need for guidance now.

Staff will be reporting to the Commission its views on the ideas expressed today, as well as any comments that are filed in this proceeding. We encourage those submitting further comments to be specific regarding potential changes to the Pro Forma SGIA and SGIP, as well as any comments on the types of processes the Commission could us to achieve potential reforms. These comments are due in 30 days, on August 16th, in Docket Number AD12-17-000.

Again, thank you for coming, and this concludes today's technical conference.

(Whereupon, at 3:48 a.m., Tuesday, July 17, 2012, the technical conference in the above-entitled matter was adjourned.)

BEFORE THE

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

\- - - - - - - - - - - - - - - - x

In the matter of:	:	
Review of Small Generator	:	Docket Number
Interconnection Agreements	:	AD12-17-000
And Procedures Technical	:	
Conference	:	

\- - - - - - - - - - - - - - - - x

Commission Meeting Room 2C
Federal Energy Regulatory Commission
888 First Street, Northeast
Washington, D.C. 20426
Tuesday, July 17, 2012

The technical conference was convened, pursuant to notice, at 9:03 a.m.

STAFF ATTENDEES:

Leslie Kerr, presiding

Arnie Quinn	Christy Walsh
Elizabeth Arnold	Michelle Davis Tom Dautel
Thanh Luong	Monica Taba
Melissa Lozano	

P R O C E E D I N G S

9:04 a.m.

MS. KERR: Good morning, and thank you all for joining us today to share your views on and experiences with small generator interconnection. This technical conference was prompted by the Solar Energy Industry Association's petition for rulemaking, to update the Commission's pro forma small generator interconnection agreements and procedures.

In Order No. 2006, the Commission encouraged interested entities to continue to work together on small generator interconnection issues. This technical conference is convened to explore possible reforms to the SGIA and SGIP, to address the issues raised by the SEIA.

This morning, we will discuss two aspects of the Fast Track process in the pro forma SGIP. Specifically, we will discuss the 15 percent screen in Section 2.2.1.2 of the SGIP, and the two megawatt eligibility threshold for participation in the Fast Track process.

This afternoon, we will have two additional panels. The first panel will discuss collection and sharing of peak and minimum load data. The second panel will discuss review of upgrades required for interconnection.

We will begin with a five minute opening statement from each of our panelists. After the opening statements, we will have questions from staff and perhaps from Commissioners. We intend for this to be an active discussion of possible reforms to the SGIP and SGIA, and to that end, hope that panelists will explore with us possible regulatory alternatives that could address the issues raised by SEIA, and that are consistent with the Commission's statutory responsibilities.

For those of you watching the live webcast or listening by phone, some of our speakers submitted materials in advance of the conference. Those materials and the agenda are available on the Commission's website. We plan to break for lunch around 11:30 and reconvene for the second panel at 1:00. We plan to wrap up the conference around 4:00 this afternoon.

Restrooms are available at either end of the hallway behind the elevators. Building management has asked me to remind everyone that only water and no other food or beverages are permitted in the Commission meeting room.

Now I would like to welcome Commissioner Norris. Commissioner, do you have any remarks?

COMMISSIONER NORRIS: Thank you. Let me just welcome everybody. I appreciate you being here today to share with us, and we thank SEIA for bringing this issue to our attention, or raising the profile of this issue, if you will.

I think this is just a good example of how we have new technologies that are providing new opportunities, but operate different than some of the technologies we had had in the past.

So how do we adapt and change operations and rules to take advantage of those new resources? That's how I view this issue. So I think you've raised some good issues about how we -- let's look at the operations, the 15 percent rule, SGIP, the two megawatt rule, and figure out how to make this work so we capitalize on what I think is just an emerging solar industry in this country.

I think the costs for solar are going to come down. It's going to become more pervasive as an energy resource from the DG level to the large scale level. How do we make changes in operation to accommodate this and capitalize on it and get it right.

So that's what I'm hopeful to learn from what I hear today, and of course you'll be building a record that I'll be reviewing with the other Commissioners as well. So thanks for all of you taking your time to give us input.

MS. KERR: Thank you, Commissioner. Now I'd like to introduce the staff at the table. To my left are Arnie Quinn and Christie Walsh will be joining us a little later. Elizabeth Arnold, Michelle Davis and Rachel Bryant. To my right are Tom Dautel, Thanh Luong, Monica Taba and Melissa

Lozano.

With that, excuse me, I believe we're ready to start the first panel. I would like to remind the panelists to please turn the microphone on in front of you when you're speaking, and turn it off when you're not.

Please also turn your cell phones off when the microphone is on, as they can interfere with the mics. Of course, everyone in the audience, including the audience, please turn off the ringers on your cell phones.

The panelists we're happy to have with us here today are Virinder Singh from enXco, on behalf of the SEIA; Carl Lenox from SunPower Corporation, on behalf of SEIA; Michael Coddington from the National Renewable Energy Laboratory; Tim Roughan from National Grid, on behalf of Edison Electric Institute; Steve Steffel from Atlantic City Electric; Jeffrey Triplett, Power System Engineering, on behalf of the National Rural Electric Cooperative Association; Jose Carranza from San Diego Gas and Electric; Michael Sheehan, Keyes, Fox and Wiedman on behalf of the Interstate Renewable Energy Council; and Rachel Peterson from the California Public Utilities Commission.

Now I'd like to invite our first panelist, Virinder Singh, to give his opening statement.

MR. SINGH: Thank you, Leslie. Okay. First of all, we'd really like to thank FERC Commissioners, FERC staff for holding this technical conference and paying attention to this issue. We think it's a very important issue.

My name is Virinder Singh. I'm Director of Regulatory and Legislative Affairs for enXco. We are a development company headquartered in San Diego. We are constructing or have developed about 180 megawatts of solar and about 4,600 megawatts of wind, and we're engaged in some other technologies.

We think this is a very important issue, and I'd just like to provide some broader context before people who are more engineering oriented, take over the discussion a little bit more as is appropriate.

Since Order 2006 was issued in 2005, growth in solar generation capacity has been absolutely dramatic, fueled in part by certain state level policies, federal incentives and declining prices. Overall in the U.S., grid-tied solar photovoltaic PV capacity grew from 230 megawatts in 2005 to approximately 2,100 megawatts in 2011, or a ninefold increase. Total PV generation capacity now is approximately 4,400 megawatts.

The states with the most active sola markets are those that also have the most assertive policies, including rebates, requirements, net metering and specific procurement programs. According to Lawrence Berkeley National Lab, up to 80 percent of grid-connected solar outside of California occurred in states that they deem as having the most active or impending solar requirements.

Some quick examples. New Jersey now has 15,778 PV projects installed in the state, totaling 770 megawatts, with another 510 megawatts in the pipeline, meaning it's in review or there's a commitment letter issued for those projects. California has 1,000 megawatts of customer-generated solar generation at 122,000 sites.

They've also begun a wholesale generation procurement program totaling 1,000 megawatts called the renewable option mechanism, and they have a feed-in tariff program that totals 750 megawatts. Hawaii has 96 megawatts of PV generation installed through the first quarter of this year. 71 megawatts of that was installed over the last two years.

Massachusetts has a 400 megawatt solar requirement, with expectations of rapid uptake over the next several years, that we don't have Q data. Hopefully we will down the road. Finally, Arizona has 448 megawatts of total installed solar generation capacity by the end of the first quarter of this year, with the vast majority of that, almost 400 megawatts, installed in the last two years alone.

Consequently, we are seeing areas where circuits are indeed being "walled off," so to speak, from further generation, absent cost-prohibitive upgrades. In Hawaii, approximately ten percent of circuits now trigger studies at the 15 percent of peak level.

A Green Wire report compared the Islands maps with red-coded circuits, indicating circuits that require extensive study, as making the Islands look like they're coming down with the chicken pox. In California, areas with particularly strong development characteristics, such as having available land that can be legally converted to solar generation from agriculture, has resulted in a concentration of wholesale DG development in counties such as Kern and Tulare in the Central Valley.

Developers are now hearing about circuits that are essentially walled off absent extensive study, and the need to build new lines to accommodate the project Q in these counties. FERC has recognized the importance of grid planning in the context of state level RPSs, as evidenced in Order 1000, which formally takes state renewable portfolio standards into consideration, in terms of transmission planning.

Similarly, we have arrived at a moment in the solar industry where all stakeholders must revisit old assumptions about what the grid can handle, and how the grid has managed to ensure reliability amid a new state level emphasis on small-scale clean power generation.

In Order 2006, FERC stated that the SGIP and the SGIA must be revisited periodically, and not less than once every two years. Stakeholders, including SEIA, did not revisit both until now, and due directly to the material impact that the 15 percent of peak threshold is beginning to exert on implementation of state-level energy policy priorities.

We must revisit. States such as California, Hawaii and New Jersey have already recognized a need to revisit old assumptions, to avoid undue discrimination towards what are relatively new market entrants in the U.S. power generation sector.

We applaud these efforts. We also believe that national models from FERC can be extremely helpful in leveraging these efforts, and informing future discussions in other states that may place a higher priority on distributed solar generation.

California's Rule 21 reforms provide the most extensive model that is appropriate for balancing the public's focus on increasing solar generation, with essential reliability considerations. Regarding the two megawatt cap on Fast Track interconnection, we support a standard that relates to the overall screen of 100 percent of minimum load.

That is, Fast Track should be allowed for projects that do not exceed the 100 percent of minimum load on individual circuits. Also note that the California Independent Systems Operator has asserted a five megawatt project size cap for Fast Track.

The 100 percent of daytime minimum load standard is still conservative in avoiding reverse power flows. Daytime load will almost always be higher than night time load, so the standard sets a bar above absolute minimum load.

Finally, I want to emphasize that the 15 percent of peak limit would still where interconnection requests are not approaching the cap, which are in plenty of places in the United States. So effectively, the revisions we are seeking would not affect broad swaths of the U.S. in the near future. The current standard would only need to be revisited when its effect is becoming material on both state policy implementation, as well as ratepayer cost.

I guess finally, I want to refer back to this Green Wire study report on Hawaii. Somebody called the current 15 percent of peak load cap "a conservative assumption of a conservative assumption." This leads to two results. A, an over-investment in distribution infrastructure, with attendant ratepayer costs.

Assuming that costs are ultimately foisted on projects, costs ultimately foisted on projects will get reflected in market prices that are paid by ratepayers. Second, we risk a potential short-circuiting of state clean energy policies. Thank you for your time.

MS. KERR: Thank you. Carl Lenox is next.

MR. LENOX: Hi. I'm Carl Lenox from SunPower, representing SEIA. I just have a few brief comments this morning. Thanks very much again for the opportunity to address this issue. It's a very important issue for our industry.

And at the outset, I want to make clear that grid reliability and safety are, of course, of paramount concern to everyone, and the PV industry has no incentive to negatively impact reliability and safety. That context is really critical as we move forward.

However, the existing 15 percent of peak load screen does result in too many projects, which are technically viable, unnecessarily being placed into a costly study process. This can be frustrating for developers. It often kills a lot of projects, and it can increase utility workloads.

The screen that's being proposed here helps to better define the interconnection process. It's part of a larger supplemental review process, and passing the screen does not automatically interconnection. So incorporating 100 percent of minimum load screen by itself really just helps to create a more structured supplemental review process.

Changing the screen will not negatively impact grid reliability or safety. The main concern is that changes to the 15 percent of peak load screen can result in unintentional islanding within the distribution system. We have put together and circulated a Tentacle white paper, which discusses why this is not the case in some detail. That's available on the back table, and I can also speak to it today.

Empirically, we have not seen any evidence of unintentional islanding issues, even in markets where much higher distribution system penetrations are routine. For instance in Germany, where penetrations in excess of 100 percent of daytime minimum load are routine and in fact reverse power flow is quite routine, we have not seen this issue.

In fact, in that country, in the spring of this year, we've seen up to 40 percent of the total electricity demand in the country served by PV predominantly, the vast majority of which was distributed PV. Just as a small commentary, we've actually seen PV installed in our country at a clip of a gigawatt per month or greater.

We've also seen that the CPUC and the California IRUs have agreed with the solar industry, that the supplementary screen will streamline the interconnection process without negatively impacting safety and reliability.

So I would just conclude that SEIA urges FERC to consider adding the supplemental screen to the small generator interconnection process. Thank you.

MS. KERR: Thank you, and Michael Coddington is next.

MR. CODDINGTON: Well good morning. Thank you, Leslie, Commissioner Moeller and good morning everyone. I'd like to give you a little background on the recent report published last January by Embril, Sandia National Laboratories, EPRI and the Department of Energy, titled "Updating Interconnection Screens for PV System Integration."

It's nice to see that there are four of my co-authors in the audience today, representing each of the organizations. So during the early development of interconnection standards, there was a great concern that the load on distribution feeders will always be greater than the amount of DG on that feeder, primarily to reduce the chance of an unintentional island.

So it's necessary for utility engineers to understand what that minimum load level was, so they could limit the amount of DG on the circuit. Very few, if any, utilities actually tracked minimum load data, but virtually all utilities do track peak annual load data on circuits.

And speaking from experience, 20 years in the utility industry, that's something I did on a very regular basis. It's how utilities plan and build new circuits when that's needed to serve load. So in order to approximate the minimum load level, engineers use a rule of thumb in which minimum load is approximately 30 percent of peak load.

If you cut that 30 percent in half, you get a very conservative number that is sure to be lower than the true minimum load. Now I'm all for rules of thumb and engineering. I mean they're great for, you know, trying to understand what the answer's going to be before you do a detailed study.

But you know, as long -- you know these rules of thumb are great as long as they are based on solid technical rationale, and I don't believe that this 15 percent penetration screen really meets that criteria. It tends to be a one-size-fits-all rule for all feeders.

When we talk about photovoltaic systems, we should be concerned about the minimum load during the period of maximum PV generation, which is referred to as "solar noon," and that's going to be between 10:00 a.m. and 2:00 p.m.

So there are numerous case studies and testimonies, which you've heard already some testimony, of large PV systems that have been through detailed studies, without need for any system modifications.

We've seen circuits operating at penetration levels of well over 50 percent, which seems to be more than anecdotal evidence that penetration may not be a limiting factor in deploying PV systems.

I believe that the 15 percent of peak load could be improved as a short-term solution methodology. Moving toward the minimum daytime load for PV system screening seems like a reasonable approach, as long as that system data is available.

Longer-term solutions, which I think is ultimately where we need to focus our efforts, we'll see advanced inverter technology and Smart Grid systems improve the landscape for interconnecting PV. So for the short term, I believe using minimum daytime load information, again if available, is a reasonable next step in improving the small generator interconnection procedures.

Most utilities use a SCADA system to gather their load information, and many of those SCADA systems have the capability to capture a defined history for each feeder, and again, I speak from experience.

That should include capturing minimum daytime load between the hours of 10:00 a.m. and 2:00 p.m. if possible. I believe that utilities could utilize minimum daytime load as a significant improvement over this peak data, again if that data can be realized.

I also believe that using supplemental review screens could be a very helpful approach, primarily to assist electric utilities in getting through some of their queue of interconnection requests.

Supplemental screens should look at issues such as voltage levels, location of the proposed system, the impedance at that location and perhaps the available fault current level at that proposed location. It's complex, that's for sure.

As the far the question of two megawatts is concerned, I struggle with that number. I think there's a question on the table about whether that should be changed. A seasoned engineer once told me, when I was quite a bit younger, that I should have a good idea of what the answer should be before I do the study.

I understand now what he meant, and when I see a system in the megawatts, that certainly is a red flag that I want to look at a system that is that large. But that's my personal experience speaking. So for the long term, I see improved methods for integrating high PV on the distribution grid, that includes sophisticated modeling systems that are fast, and require much less time than the systems we use today.

Think of using a PV interconnection easy button, as it were, with an advanced study tool, and certainly the national labs, the Department of Energy, groups like EPRI are working diligently to develop such tools. Finally, advanced inverters, electrical storage systems, robust communications and control and a more intelligent grid will all be part of the long-term solutions. Thank you.

MS. KERR: Thank you, and next we have Tim Roughan.

MR. ROUGHAN: Thank you, and I want to thank the FERC for hosting us here today. It's almost ten years ago this summer that we had this same discussion, relative to small gen procedures, and at the time, there was proposals put forth by the industry suggesting various changes.

At the time, it was very important that we all work together as a group, to come up with what then became the operative Order 2006. I think the main purpose of my comments representing EEI is the same process really does need to be followed. I think there's lots of different utilities at different places in terms of interconnecting large amounts of solar.

California utilities, up in the Northeast and Massachusetts, for example, just to help the first speaker. We have over 850 megawatts of solar proposed, and about 115 megawatts installed in Massachusetts. That 850 megawatts has come about in just the last two years.

Two years ago, the largest project we were seeing looking to be interconnected in Massachusetts were 50 kilowatts, 100 kilowatts. Now it's fairly routine to get three, four, five megawatt proposals on the local distribution, local distribution circuits that feed three to five thousand other customers.

The key point of doing the interconnection analysis, whether with screens or reviews, is to make absolutely sure that once that system is interconnected and operating, that it does not affect the customers next door. This is a very different animal from larger projects that typically have interconnected to transmission level and larger and higher voltage systems. When you're connecting to local 12 and 13 kV systems, you really have to recognize that there are significant issues out there.

Most of the solar projects that we're seeing in Massachusetts and Rhode Island, because they have similar subsidies now, are out at the fringes of our distribution system, because that's where the land is available and inexpensive to build these projects.

Had they been proposed in the load centers, very different things could occur. But because of where they're being proposed, it causes significant issues relative to again, the neighbor's power quality and their reliability as well.

So it's important to recognize that at a high level, and I see today as a repeat of ten years ago, where we really need to get together with the industry, as the electric utilities come up with a plan as to how to move forward and potentially modify the small gen procedures.

Because it's very important as we go forward to continue to support the states that we all work in. You know, EEI and National Grid and the utilities are very supportive of the state policies that are promoting renewable energy, and we have been engaged specifically in the legislative process to get those policies and procedures put into place.

And working together with the industry, we can come up with ways to streamline the process. But I think it is premature to simply change the rules because today, it appears that it's getting more difficult to interconnect solar. It's more difficult simply because of the size of the projects are so dramatically different than just a few years ago for many parts of the country.

When you're talking four megawatts on a circuit that typically has a peak load of five or six megawatts, it's a significant impact. The issue of minimum loading is also concerning to us, because again, it will and can affect the flexibility of the system going forward, if you now have to maintain a certain amount of minimum load on a circuit out there.

The 50 percent limit was put in place as a conservative level, to make sure we wouldn't affect the neighbors, and going forward, whether that needs to be adjusted or changed is again part of a consensus-building effort that I think we should probably embark on going forward.

Because there's many issues that do need to be looked at. You know, we are all working through how we're going to increase the reliability and safety of our systems through additional intelligence and communications, the Smart Grid, if you will.

As we go forward, we need to understand how we need to modify some of those proposals that are already in front of some regulators, in terms of how to accommodate additional amounts of renewables, whether it be solar, wind, landfill gas, biomass, etcetera. There's lots of other opportunities out there which we really need to properly address.

And in terms of the two megawatt value, again we're talking circuits where in the locations they're being proposed, the peak loads aren't very much higher than the two megawatts. So you really need to get into the details of the review, to make sure that when you're done with the review and it goes online, it will not affect the neighbors' reliability and power quality safety.

Because once they're online, there's not anything we can do about them. So we need to be absolutely sure, when we're done with our studies, that what we've agreed to through the interconnection agreements will provide for a highly reliable system, that will produce all the benefits of renewable energy which the states and the country need, but conversely also work well with the utility distribution system in the area, to maintain that high level of reliability that our customers have grown so accustomed to over the past few decades. Thank you.

MS. KERR: Thank you, Tim. Next we have Steve Steffel from Atlantic City Electric.

MR. STEFFEL: Thank you very much for the opportunity. I'm Steve Steffel with PEPCO Holdings, Inc. Atlantic City Electric is one of our utilities, as well as Delmarva Power in the PEPCO area, right here in Washington, D.C. All of our areas are experiencing solar integration. We've got about 150 megawatts total right now, and increasing rapidly.

We do support solar integration. We've made the SEPA Top Ten List with Atlantic City Electric for the last couple of years, and while PHI supports increased solar and other distributed energy resource additions, and we do have a number of other ones that apply to and we have to accommodate all of them, we remain focused on maintaining a reliable grid for customers.

PHI is supporting a lot of the efforts that develop advanced technology. In inverters, we've already worked with one inverter company to develop new software. We're working on advanced modeling programs so that we can actually assess grid impact very quickly for applications. We have measurement data collection systems out there. We're working on new communications.

We want to accommodate all the renewables that want to come on the grid safely and reliably. One of the things, though, that is a takeaway, if we do have installations that cause negative impacts on the grid, it will ultimately hurt the solar industry or those industries that are attempting to put that type of equipment on the grid.

We do have a lot of pending systems, and so that's some of our focus. One of the things I'd like to mention and point out, and it is available in the handouts, but we're just going to touch on some of the highlights, on hosting capacity.

EPRI just did a recent study on one of our rural feeders, and the study came back that the minimum hosting capacity could be as low as 3.3 percent, depending on where you put the inverter-based systems, the solar systems.

Then they compared it to an urban feeder, and the urban feeder was similar voltage, similar load and peak. Had a much, much different, much higher hosting capacity. So this is something that we've got to keep in mind, is that there are all kinds of feeders out there with different characteristics and different hosting capacities.

One example I'll give, and it's also on our handout, we just experienced that. We have a system that 1.3 megawatt AC PV system, 1.8 miles out from the substation. This particular feeder, we know that typically it's around 30 percent the minimum load to the peak load.

But this particular feeder had a 15 percent daytime minimum load. It's quite an anomaly. There's not a lot of feeders like that, but this one had a lot of industrial customers. So we experienced in the spring time, when you typically have your maximum output, there was some reverse flow on this feeder.

It wasn't anticipated by our planning engineers and it had passed the screens, and it had gone in without any detailed study. Well, it caused reverse flow on a voltage regulator right outside the substation. That regulator went to maximum raised position on the feeder, and it caused damaging high voltage for several closer-in customers.

Even though the inverters tripped later on at the solar site, the closer-in customers experienced high voltage and actually resulted in significant damage to equipment. So it is very possible to have that condition, and there's other, many other feeders, irrigation feeders, different types that have loads that area not predictable.

Economic changes. These particular industrial loads on this feeder probably operated seven days a week, cut back on the weekends, and resulted in this situation. One of the other things is that this can occur on any feeder, where you have a voltage regulation zone.

If you don't have the voltage regulator set up for reverse flow from a co-gen unit or a PV unit, you can experience the same problem, and there's voltage regulators on feeders that haven't been set up for this type of phenomena. So you can have little ones, big ones that cause that.

In summary, the 15 percent screen is good for the vast majority of circuits, and should be maintained. However, it should not be viewed as a failsafe screen, and utilities should have the discretion of doing further study when initial investigation warrants.

A situation in the case study can easily be repeated on feeder regulation zones by the addition of small or large PV systems in aggregate, causing reverse flow on a voltage regulator not set up for that condition. As more and more solar is integrated over the period of time, the historical peak, the daytime loads become masked and screens become more difficult to use accurately.

And hence, the need for very conservative screens. The more you want to go away from conservative screens, the more time it's going to take, and you're not going to have a quick assessment tool. DA and reconfiguration schemes must also be considered, and our utility has a goal of putting that in across the board to increase reliability.

Systems less than two megawatts can have a significant impact, as we just saw in that example, so the two megawatt threshold should remain. That concludes our comments.

MS. KERR: Thank you. Next is Jeffrey Triplett from Power System Engineering, on behalf of NRECA.

MR. TRIPLETT: Well thank you to the FERC staff and the Commission for the opportunity to speak on behalf of the National Rural Electric Cooperative Association. The question on the table today is whether or not the existing SGIP screens, and in particular the 15 percent screen, still provides a valid means to determine whether or not an interconnection should be chosen for a Fast Track process, or whether it warrants further study.

And the existing screen, if you look at the last, since the screens have been implemented, the proof of what they've been able to achieve, the screens have shown that they are sufficiently conservative, such that PV and other generation that has been interconnected with systems on an expedited Fast Track basis hasn't proven to cause harm to the system.

But it's not shown itself to be so conservative that generation interconnections can't get into the Fast Track process. Thousands, in fact, have qualified for the Fast Track process and have been done through that process.

Those that did require further study, because they didn't pass a screen, were able to be accommodated through the study process by determining what the issues to the system were and then developing solutions to those issues.

If we look at what has changed since the original screens have been created, nothing material has changed in the utility industry as far as how we design and operate the electric utility system. Nothing material has changed in the way that generation is interconnected with our systems.

What's changed is that we have a lot higher penetration of DG on the systems, and that's what's warranted the review of this screen. Review is a good thing. We should periodically review these things to determine if they're still meeting the needs that they were originally intended to meet.

But the fact of the matter is most utilities, especially the rural electric cooperatives that NRECA represents, do not have significant experience with high penetrations of DG. It just hasn't happened yet.

There certainly are places in the country that have been mentioned here, earlier in discussions, that have seen high penetrations of DG, and I'm sure that there are some utilities that have more comfort level with those penetrations.

But in general, the industry as a whole is not ready for high penetrations without certain types of screens to determine whether study is required of those high penetrations. If we look at adding supplemental screens to the process, especially those as proposed, it undermines good utility planning.

When we plan the system, we plan it to not operate at its operational limits. We have safety margins. We have certain levels of safety and reliability that we have to afford our customers. If we operate the system near its thresholds, then we're not doing our due diligence as utilities and utility planners, to ensure safety of the grid and the consumers connected with it.

If we look at the 100 percent of minimum load supplemental screen that's being proposed here, just on the surface you can see that it's right at a threshold. One of the concerns associated with interconnections is reverse power flows, as we heard another panelist speak to.

At 100 percent of minimum -- at 101 percent of minimum load, reverse power flows occur. So we're operating right at a threshold, and operating at that threshold without allowing study, to determine what impacts to the system might happen should 101 percent of minimum load be achieved, which is pretty easy on the utility system to see changes in load over time, is just not doing due diligence in the planning of the system.

If we look -- there's lots of other technical reasons why looking at the proposed supplemental screens cause concerns. I've submitted those in a written statement, so I won't go into those technical reasons just at this time.

But there are certainly better alternatives to reviewing these screens, and whether or not supplemental screens are required. As I mentioned, it is good to review this process, to determine if it's still meeting the needs. There are working groups, IEEE 1547 working groups right now that are working on similar issues.

1547.7 is reviewing the system impact study requirements, what should trigger those types of studies, routine studies and advance studies. 1547.8 is looking at high penetrations of DG and what might need to be done to accommodate those safely with utility systems.

These types of working groups with technical experts is really the perfect forum to be talking about these screens and what changes might need, and I would encourage everyone to consider letting those working groups work through their process, to determine what changes might be useful. Thank you.

MS. KERR: Thank you. Next we have Jose Carranza from San Diego Gas and Electric.

MR. CARRANZA: Good morning. I want to thank the Commission for the opportunity to participate in today's technical conference in behalf of San Diego Gas and Electric. My name is Jose Carranza and I am the Electrical Distribution Planning Manager for San Diego Gas and Electric.

I'd like to say that SDG&E has an extensive experience with connecting small-scale net energy metered solar projects in its service territory, and is a signatory to the California Public Utilities Commission Rule 21 settlement.

SDG&E believes that the current Fast Track program, including the 15 percent screen and the two megawatt limit, provides a workable and efficient means of facilitating the interconnection of small generating facilities. SDG&E's experience with the current Fast Track process does not necessarily mean that there is not room for improvement.

However, SEIA's proposal would not be an improvement in our opinion. The proposed changes to the megawatt limit and load screens do not take into account that all systems are not the same, especially the distribution systems.

The changes would likely violate the technical and operating limitations imposed by our distribution system's electrical characteristics, and thus be unworkable in many instances.

Examples of unacceptable operating conditions that must be avoided when interconnecting generation include, but are not limited to, over-voltage conditions, under-voltage conditions during transient generation, because our equipment does not respond fast enough, especially if there's regulation on circuits.

Conditions that cause those type of situations to happen are when clouds or marine layers occur, as such is the case in San Diego. Many days, there's a marine layer that comes in and lasts for the whole day.

So in regards to Rule 21, the CPUC Rule 21 distribution interconnected settlement concludes that the initial phase of the CPUC process for revisiting the interconnection rules, and is not the ultimate solution of how to improve the interconnection process in California. We still have a lot of work ahead of us.

There are two interdependent phases. Phase 1, which we're wrapping up, establishes the framework of the interconnection process. Phase 2 will address several other salient issues that remain on the table, which includes further revisions that we anticipate will be the 15 percent threshold screen. We're probably going to revisit that in the next few months.

As part of the Rule 21, we revised the supplemental, we created a supplemental review and associated technical screens. The supplemental review is triggered when an interconnection applicant proposed generating capacity causes the aggregate generation capacity on a line section, not the circuit, to exceed the 15 percent peak load.

There's been a lot of discussion about the 15 percent and 100 percent minimum load here, but what's forgotten to be mentioned is it's of every line section protected by an automatic device. That could be a fuse; that could be a recloser; that could be a circuit breaker.

So we've got to make that differentiation, that it's not just the load on the circuit. It's the load on every line section. The supplemental review looks at the level of penetration of self-generating capacity, as I mentioned, measured against 100 percent of the line section minimum load. Again, I want to stress that, because it's very important that we understand that it's the line section minimum load.

We've got to consider whether the power quality and the voltage can be maintained within the defined limits, when we allow 100 percent penetration, and whether any additional safety reliability impacts are present.

The new 100 percent of line section minimum load screen is applicable only to projects undergoing the supplemental review. So if you come in and you're above the megawatt limit, the two megawatt limit, or the 15 percent threshold, you will go into a supplemental review.

In the supplemental review, 100 percent of the line section minimum load screen is a screen that we have, but we must consider it along with other screens, which we call the power quality and voltage test screens for reliability and power quality verifications.

The Screen O and Screen P, which is the power quality and the reliability tests that we have built into the Rule 21, in 100 percent of the line section minimum loads screens are interdependent. We can't do it without each other. Without the Screen O and Screen P, the 100 percent of the line section would be problematic, as there is no way to verify that the power quality and the reliability are impacted.

It's very important for the safe operation and reliability operation of our systems that we do that. The 15 percent threshold screen continues to function well as a rule of thumb, permitting interconnections without additional study, and has been left in place in the initial review component of the Fast Track process.

The 15 percent threshold screen rule should not be replaced by 100 percent of the line section minimum load screen. As mentioned earlier, it puts us right up against the limit of our distribution system, would could cause problems if load should go away. So we've got to be very considerate of how much load is on a circuit, because it's a snapshot of today when we do the studies. Tomorrow may be different.

Speaking for SDG&E and its distribution system limitations, the current Fast Track program, including the 15 percent screen and the two megawatt limit, provides a workable and efficient means of facilitating the interconnection of small generating facilities to SDG&E's distribution system.

SEIA's proposal could potentially slow the Fast Track process for all projects, especially if the two megawatt limit is raised to ten megawatts or done away with, as is proposed. Such a removal of those limits could increase the generation size that is being proposed and thus, since it's moving away from the two megawatt limit, potentially also increase the number of projects that are failing to go through Fast Track, and impact our work flow.

Data on minimum daytime loads for periods between 10:00 a.m. and 2:00 p.m., as mentioned earlier, is not readily available for line sections of the distribution system. We don't have monitoring equipment everywhere. We don't have SCADA everywhere.

We typically install SCADA at the substation. It may be midway down the circuit, it may be at a tie at the end of the circuit. But you have many branches of circuits that do not have any type of load monitoring on them.

SEIA's proposal to use less rigorous screens and limits may not be reasonable, given our distribution limitations. The screens in the Rule 21 settlement were developed to provide the flexibility that helps address the differences in each IAU's distribution system, differences such as distribution system design, equipment, operational differences among each utility. Even in California, the three utilities have different ways of operating our system.

The differences impact the amount of penetration that can be safely and reliably interconnected onto our distribution systems. Other factors that my impact the penetration levels on the distribution system include, as I mentioned earlier, the size of the generation, the location of where the interconnection is occurring on the circuit, the amount of load on a line section, especially on minimum load days, and where we don't readily have that information available, as may have been thought previously.

The distribution system voltage also plays a big part in the amount of penetration that could be afforded in a circuit. The higher the voltage, the stiffer the circuit, potentially allowing penetration to go up. Not all of us have the same voltage on our distribution system across our systems.

Length of feeders and branches play another big role, and to make things a little more complex, not all of our circuits have the same design and capacity built into them. So I guess what I'm trying to say here is our systems are different, and interconnecting into our systems is not an easy thing. It's a complex thing that we have to study.

We believe at this time that a rulemaking is premature. We believe that potentially the Commission should continue to explore putting working groups together, to have the engineering and everybody else work together in groups, to come up with a consensus on what modifications need to be made as we move forward, to hopefully improve the penetration levels on our systems. Thank you for your time.

MS. KERR: Thank you. Next we have Michael Sheehan from Keyes, Fox and Wiedman, representing IREC.

MR. SHEEHAN: Thank you, and I wish to thank the Commission for this opportunity to -- but first, a little bit about IREC in case you're not familiar with it. We're a 501(c)(3) organization, so we do no lobbying.

But we do interconnections at the state level. We've been in 30 states in the last three years, and currently we're involved with California, Hawaii, Massachusetts, New Jersey, Washington and we're basically -- we do this on a state-by-state basis. So we're very involved at the state level.

I'd like to start off by saying that you've heard this morning that basically the 15 -- utilities feel very comfortable with the 15 percent screening. The problem is not just the 15 percent screen; the problem is what you do when you're above the 15 percent, and how do you handle that above 15 percent?

What we believe, the results that above 15 percent is that the systems are subjected to more study than is needed. This can undermine the cost effectiveness, particularly of small and residential commercial systems.

We think a different approach is needed for interconnections for those systems, and we applaud the approach -- we basically look at the supplemental review approach, as a way of getting being able to address the above 15 percent screen.

In this approach, the supplemental review has been, it's part of the SGIP. It's part of Hawaii's 14(h) and California Rule 21. We think this supplemental review process is a way of addressing the above 15 percent limit.

California and Hawaii have added a lot more detail to the supplemental review than that's in the existing FERC SGIP. In addition, we've been talking with SMUD. SMUD is the Sacramento Utility District, and they're presently using the 100 percent of minimum load.

One of the things that SMUD is doing is it's doing a calculate and measure approach. What they're doing is they're calculating what they think this minimum load should be, and then they're using a measurement device to go out there and measure kind of what's going on.

That calibration is giving them a lot more confidence that their models are actually performing the way they want it to do, because as Jose pointed out, the system is dynamic and it does change, and you need to make sure that you calibrate and you develop a risk tolerance that you feel comfortable what you have on your system is what you expect to have. So we think that's an important, another step in this process, of how to develop a better tool.

IREC endorses the proposal Rule 21, with both, with the review approach for penetrations about 15 percent of peak, up to 100 percent of minimum load. Maximum load currently is relevant to circuit criteria for interconnection process. Minimum load is currently relevant for the interconnection process.

Utilities currently look at the extent to which the generation capacity may exceed the minimum load of the interconnection process. We propose to make the consideration more transparent. Part of what we believe it needs to be the existing screen of 15 percent. Above that is not very transparent.

So what we have worked with with PG&E, SCE in California was to develop screens N, O and P, in particular to develop a lot more transparency, so that people would see what's actually going on once you get above that 15 percent.

We worked closely with them to develop those screens. In particular, Screen O goes back to kind of the Embril Sandia report. Screen O points out within 2.5 miles on a 600 amp wire, which is big wire and close to a substation, you can get a lot higher penetrations, and it gives a lot more detail for people, so that they can see what's going on in the feeder, so they'll have a better understanding as they're applying to these systems, and to get to higher levels of penetrations.

We feel one of the other benefits that this has is that there's a fee associated with the supplemental review. It's not a free step. The developer has to pay for this. It gives more information, but it's a more step-wise process, because right now you go from a Fast Track process into this study process, and you get lost in the study process because that could take long, long time typically.

So we believe that with the quick review with the supplemental review, it's a lot more useful for the developer if they can fall into that, those screens, and pass those supplemental review screens. We feel it's a lot better approach doing it. And again in Hawaii and California, we've added a lot more detail into that and to those screens.

MS. KERR: Okay, thank you. Last we have Rachel Peterson from the California Public Utility Commission.

MS. PETERSON: Thank you, and I'd also like to thank FERC's staff and Commissioners for having today's technical conference, and for the opportunity to speak about some of the reforms currently being proposed in California.

My name is Rachel Peterson. I'm the analyst who's advisory to the open rulemaking at the CPUC on distribution level interconnection protocols. Those are primarily contained in the CPUC jurisdictional Rule 21 electric tariff.

I'd also like to mention that CPUC's general counsel, Frank Lind is here as well. I can't see him. Oh yeah, Frank, and he and I really worked at a staff level to facilitate the settlement process that you've heard panelists refer to.

So what I'm going to speak from today is really two pieces of that settlement that are relevant to today's panel. But if you have, if anyone has additional questions about the settlement process, Frank and I can certainly answer those questions.

I did submit written materials. There are hard copies of those at the table at the front of the room. Then last, one more piece of context. There are a number of other signatory parties here today. I'm really pleased to see that IREC, San Diego Gas and Electric, Southern California Edison are all present in the room, and can speak very knowledgeably to what we've done in terms of proposed reforms for Rule 21.

California's at the forefront of procuring renewable energy. Starting in the middle of this past decade, we began to create procurement programs specifically designed to bring or encourage exporting generating facilities to interconnect to the utility distribution system.

Some of the best known are the renewable and combined heat and power feed-in tariffs, and the renewable auction mechanism, also known as RAM. Those programs provide a blend of avoided cost and market-based pricing, under which the generating facility sells the power either to the host utility or into the wholesale markets.

These programs are in a different place on the distributed generation spectrum, from the California solar initiative and net energy metering tariffs, which have rules specifically limiting the customer to designing their system so as to offset onsite load.

The generating facilities that participate in the feed-in tariffs and RAM are built to export some or all of their output, and they can range in size from below 500 kilowatts to 20 megawatts. California initiated these programs with a range of policy goals in mind, including reducing greenhouse gas emissions, greening the energy supply and stimulating the market for lower cost renewable energy.

Those policy goals also share a lot in common with California's interconnection policy, which has its roots in PURPA, and is intended to emphasize a clear and predictable path to interconnection for non-utility owned generation.

Now what California has done with the creation of those procurement programs is to place interconnection of exporting generators on the utility distribution systems, at a crossroads that is at times rife with conflict.

The key interconnection fact about the generating facilities participating in the feed-in tariffs and RAM is that location decisions are driven by any number of factors, some of which we've heard about already, such as remote locations, where the solar resource in California is strong; the location of an industrial facility or a dairy; or land prices low enough to accommodate a PV system of the size that's needed to make the project economics work.

As developers join in these programs file interconnection requests under Rule 21, two problems that are relevant to today's panel became apparent. First, an interconnection tariff that places all exporting generating facilities into a serial study process is only functional up to a certain point. There is a point at which the volume of interconnection requests simply becomes too much for the utility to handle.

This is the case under the presently effective Rule 21, in which if you are an exporting generating facility, you're automatically placed into supplemental review or detailed study.

The second problem is that the introduction of programs like the feed-in tariffs, that emphasize the export of power onto the distribution system, alongside the locational decisions being made by developers, such as places where aggregate generating capacity might be already high, or load levels at present might be low, places pressure on the exact screen that designates expedited interconnection as based on that relationship between aggregate generating capacity and load.

So these problems are a piece of the why, which is why California undertook a settlement process to reform Rule 21, and they also at the same time present the question of what, to try to encapsulate in a single question for today's panel.

Can the Rule 21 technical screens be expanded to identify the conditions under which an exporting generating facility can have an expedited and predictable path to interconnection? This is one of the questions that the settling parties wrestled with, and they ultimately answered it yes.

They introduced two key components to Rule 21 that are relevant to today. The first is a new penetration threshold, which other panelists have already spoken about, and the second is new exporting generator size limits for the Fast Track process.

First, as to penetration. The settling parties retained the 15 percent of peak load threshold in the initial review track of Rule 21. This is because the 15 percent screen has been keyed to expedited interconnection of over 100,000 generating facilities in California, without compromising safety or reliability.

They added a second penetration threshold to supplemental review, and I'll go ahead and read the text from the rule. It asks "Where 12 months of line section minimum load data is available, can be calculated, can be estimated from existing data, or determined from a power flow model, is the aggregate generating facility capacity on the line section less than 100 percent of minimum load for all line sections bounded by automatic sectionalizing devices upstream of the generating facility?" It's in the written materials.

This is a national first, and in California, if it is ultimately approved by the CPUC, we and the settling parties anticipate that it will permit expedited interconnection of generating facilities that would otherwise have been placed in a detailed study process.

The second major change was made by the settling parties, in order to aid in managing the number of generators applying to Fast Track in the first place. The settling parties agreed on certain size limits for exporting facilities. Those range from 1.5 megawatts to 3 megawatts in the different utility service territories.

I want to mention that the settling parties also proposed a number of transparency and predictability-related reforms, many of them drawn from the SGIP, which Rule 21 was lacking, and which they felt were essential alongside the new screening process to making the tariff actually functional.

The CPUC has not yet acted on the proposed settlement, and so these modifications are not yet part of the approved tariff, and in addition, we do anticipate that a Phase 2 of the rulemaking will open, once the CPUC acts on this first Phase 1 proposal, with potential further modifications to the tariff, focusing on cost allocation policy and technical operating standards.

If the CPUC does approve the settlement, the parties anticipate that the interconnection standards in California will catch up to today's forms of procurement, and support both procurement and interconnection policy goals, which is something that grown out of whack over the last several years.

So in that vein, I hope that the reforms proposed in California offer a model for a regulatory approach for federal interconnection standards, if the needs due to rising application levels and rising penetration levels are becoming as acute as has been California's experience. Thank you again for the opportunity to speak.

MS. KERR: Thank you, Rachel. Before we begin our discussion, I would just like to ask if you want to speak, put your table tent up so that I know that you want to speak, for both staff and panelists.

I'll start off with a question that some of you may have touched on. What are the implications, in terms of cost in time to a small generator, of going through a full study process versus the Fast Track process, either because it's larger than two megawatts or because it fails the Fast Track screens? Sure, Mr. Singh.

MR. SINGH: I'm just going to refer to SEIA's response to comments on the petition. So you asked a simple question on its face. Unfortunately, the response is very complicated. We've heard every system is different, so on and so forth. Well unfortunately, it seems like every utility process is different.

In the distribution realm, I mean obviously on transmission there's, I think, greater transparency on the transmission interconnection process across the country. What we're seeing, and this is partly due to the fact that this is a new market, and everybody's dealing with this as a new thing. So we definitely understand that.

But what we see, when you ask about cost, in the comments that SEIA provided, I'll actually refer to a SunPower statement, that for one, certain utilities are using the 15 percent criteria as a hard limit to arbitrarily control interconnection capacity on certain wholesale projects.

Once the amount of proposed solar generation exceeds 15 percent, all additional projects, be they wholesale or retail, are getting rejected by certain utilities. So I don't know what the cost is of that, if the cost is infinite or in a sense, the utilities are saying the cost is infinite.

Other utilities that have closed off certain selected circuits to interconnection have been unwilling to present their criteria, or to set up a transparent process for reviewing decisions being made to use the 15 percent screen as an absolute limit.

I'll reference, SEIA referencing Sun Edison, which said that they have four projects with a total capacity of 6.2 megawatts that failed the 15 percent screen, but then they had to go through a full two-year study process for a 6.2 megawatt suite of projects. So the cost to a developer is either excessive time, or just being told no in some of these examples.

So I wanted to emphasize that. Every utility has their own process, but we're seeing the 15 percent screen as presenting frankly unbearable hurdles for getting projects done, which is one of the reasons why we need to see a change in the overall screen.

Now if there was a clear process for a supplemental study, that was frankly concomitant with the real impacts that these projects can trigger. There might be greater comfort, but the fact is that it's triggering some of these, some hard to understand processes that take a lot of time, or we're just being told no. So --

MS. KERR: Okay. Mr. Roughan.

MR. ROUGHAN: Yeah. So in terms of the Fast Track versus the study process, there's obviously typically in most utilities some sort of impact study fee. Those fees range from a few thousand to fifty plus thousand based on, you know, how big the project is. Because you go through the estimate of what it's going to take actually to look at the particular project.

As Virinder mentioned, you know, this is new for a lot of us, in terms of getting the multiple megawatt projects. They didn't exist just two years ago, for most of us, and so we are learning as to how to do them better going forward. But ultimately, where the utility is has, I would think in most cases, if not all cases, has reliability standards they're penalized by their state regulators on.

It's very important that the utilities do take a conservative look at what they do need to do. As the utilities become more comfortable with the screens and understand more that they aren't impacting the reliability and other issues, then they will learn from that and are learning from that going forward.

I think the real issue here is just simply the massive volume of solar projects, you know, prompted by the subsidies and also prompted frankly by the base cost of the systems and panel costs have dropped dramatically in two or three years. And also what we're seeing is a lot of developers are new to this market as well. So they're just learning the processes as well.

In terms of a three, four, five megawatt project that, you know, will cost 10 to 20 to 30 million dollars to install, you know, a 20 or 30 thousand dollar study that takes somewhere, depending on the utility and the amount of volume they have, four to six months to complete, is a small price to pay on the larger system and the reliability required by the state regulators, by our customers.

I mean we just went through a very serious scenario down here just a few weeks ago, and people get very, very upset about reliability. It's the utility who pays for poor reliability.

So the need for the studies is there. Over time, I can imagine as folks get more comfortable with the screens and see that they are working, they could pursue those. But at least for our experience, we clearly detail what we're doing. We try to give as best a time estimate as we can.

Unfortunately, with the volume of projects, it does affect that. You know, what folks also need to recognize there's a dearth of experience, utility and outside consultants and contractors who understand how to deal with multiple megawatt projects on local 13 kV distribution.

We're slowly building up that talent pool again, but it just frankly didn't exist up until a few years ago. So there was a period of time as the industry has to react, to get the talent in place, to be able to do these in a quicker fashion.

You know, we talked about the seasoned folks who do utility reviews. None of those folks ever dealt with a multiple megawatt intermittent project on local distribution. They've dealt with multiple megawatt combined heat power projects; they dealt with transmission interconnections.

But the reality is this is a new animal that we're facing. It's a significant challenge that we're taking on head on, and are very interested to get these done.

We want these done as quickly as possible as well, to free our people up for other work. There's lots of other work the utilities still do every day, beyond interconnection DG, but are interested in streamlining the process over time.

MS. KERR: Okay, thank you. Mr. Carranza.

MR. CARRANZA: Thank you for your comments, Tim. I really agree with what you were saying. But I want to add a couple of things here. I think there's a dual responsibility not only on the part of the utilities, but also of developers. In California, we've taken the step to put maps of our system on a website, where developers can go and look at the capacity of particular circuits, available capacity for connecting distributed generation on our circuits.

Many times developers will submit projects that exceed the capacity of a circuit where they want to interconnect. Many times, they're interconnecting out in our rural areas, where the capacity of our circuits is either limited, or the system is weak by design, because there hasn't been very much load out there.

So my point is we need to work together. We can't make capacity available that's not available. You need to work with us in order to be able to get your studies done quicker too.

MS. KERR: Okay. Mr. Steffel.

MR. STEFFEL: A quick follow-up. When you say you post the capacity that's available, is there any simple insight into what that capacity number is based on? Is it based on the 15 percent screen, for instance?

MR. CARRANZA: We put two numbers together. We basically post the maximum rating of a particular feeder, and we also post the minimum capacity which is the 15 percent of load, peak load on that feeder.

MS. KERR: Another follow-up for Ms. Peterson. I understand through Rule 21 there will be an additional report that will be available to developers. Will that have more information than the maps currently have?

MS. PETERSON: Yes. You're referring to something called the pre-application report. So it's a new report that the settling parties proposed. It is intended to work similar to what Mr. Carranza was just referring to. You can pay $300 and get a first look from the utility about your proposed point of interconnection.

It is limited to data that already exists, say technical data about the distribution system where you're looking to locate, as well as existing peak load levels. Any data that they do not have to calculate or measure or conduct some form of analysis for. But it would provide more information than the interconnection capacity maps, yes.

MS. KERR: And it sounds like it's fairly localized for a specific area?

MS. PETERSON: It's driven by -- your report is what you request for your point of interconnection. If you look at the maps, you begin to see broader areas, surrounding substations, particular electrical areas where the three investor-owned utilities in California have identified capacity levels.

MS. KERR: Okay. Mr. Steffel.

MR. STEFFEL: Although we can't comment for other utilities, our utility actually does a static load flow screen, to determine whether something would need to go on for study. So sometimes we can approve connections of systems that would fail the FERC screens, based on our internal study.

Right now, we use a third party vendor to do the studies. It's usually between 20 and 30 thousand. Depends how complex it is. Takes generally up to eight weeks. Sometimes it is a little more, sometimes a little less.

I think one of the challenges, just like Tim had mentioned, is we found that third party vendors even had to be coached on making sure they got things right, and so the talent and the skills are really being developed for doing the studies correctly.

If you get the study wrong, you're going to have a problem on your hands, possibly for a long period of time. And, you know, it only takes one system to go in to cause problems for a long period of time for a lot of customers.

So that is a significant factor.

But we do, anything we can do internally we do, and we don't send anything out. We do that for free for all the developers. That is within generally just a few days, within that 15-day period. So very few of them percent-wise go out for the detailed study.

MS. KERR: So some folks have already addressed this, but just to make sure we have a clear picture of it. We're interested in whether there are regions or locations where it's difficult for small generators to take advantage of the Fast Track process due to the 15 percent screen. We've mentioned, some of you have mentioned states, but we're also interested in different parts of utility systems. If anyone can address that.

MR. ROUGHAN: As I mentioned, you know, many, most, I should say, of the projects we're currently seeing developed in Mass and Rhode Island, are on the fringes of our electric distribution system, because that's where the land is available, that's where it's, you know, economically feasible for the developer to pursue the projects.

And you know, when you're on the tail end of the system, A, there's not a lot of load that's required, that was required to be served. So now you have to upgrade the whole system. You know, a lot of places you've got single phase or three phase extensions that have to be built.

You've got different substation modifications or recloser modifications on those circuits, systems that simply don't play well with a simple screen.

You really do need to do the analysis as to how that's going to interact, because in many of those locations, on a beautiful late May afternoon with max solar output and minimum load in the area, you've going to have export up to the transmission system through the local substation.

We're seeing more and more of that as time goes on, and again, it can be dealt with. We study them. We interconnect these projects. They go online, but there is that needed piece that has to be done, of the study and typically extensive construction. But then we can get these projects online.

There's really no reason a project can't be interconnected. It's just simply sometimes takes time and money, and ultimately, things like having maps or pre-application reports that lots of us do will guide that developer. One of the really curious things we've seen since the state subsidies went into effect in New England is that up until a couple of years, virtually anyone who was going to interconnect to the utility called us prior to sending in the application, and wanted to know what the issue was, an initial kind of discussion.

Since the changes in the subsidies, that vary in nature, these projects are just coming in. For a while, they were coming in a clip of five to 20 megawatts a week to our interconnection folks in Massachusetts. Well, you didn't even know that they were -- they hadn't called us. They hadn't asked for anything to look at first. They were just coming in the door.

Then when we did review them, we said "oh lookit, we've got some issues here and what-not." We have developers fighting for the same parts of land in certain cities and towns. That's always a challenge, who owns the property, who's got the rights to do it.

So there's a lot to this, and I think as both the developer and the utility communities mature as to how to deal with these, I think we'll be over this issue that temporarily -- that I believe is simply a temporary issue that we'll be able to work our way through.

MS. KERR: Mr. Lennox.

MR. LENOX: Yeah. I wanted to comment that it's important to just keep in mind that what we're talking about here is that the 15 percent screen is often being used as a ceiling, as opposed to being used as a floor, and that significant reform in the Rule 21 settlement is a use of that screen as a Fast Track floor in essence, and then defining a set of screens that give a lot more -- give a lot more structure to what happens to a project that does not pass that 15 percent of peak load screen, and provides a method of getting projects online that's defined, as opposed to status quo, which is undefined.

That's really what we're talking about here. So when we talk about what the cost is, the cost is going from a defined process to an undefined, open-ended, in terms of cost and time frame, process. That's the pain.

MS. KERR: Okay, thank you. Mr. Carranza.

MR. CARRANZA: I think we've got to be careful with the 15 percent screen and making it the floor, because there are many circuits that potentially can't even accept 15 percent penetration, and making it the floor may impact reliability in the operation of a particular situation.

MS. KERR: Ms. Peterson.

MS. PETERSON: Yeah. So you asked whether there are regions or locations where it's difficult for developers to take advantage of the 15 percent screen, and I think both of the prior folks who just spoke are both right. The 15 percent screen is one of a number of questions that are asked during the Fast Track process.

A number of others deal with other technical issues, such as short circuit current contribution, short circuit interrupting capability, the line configuration.

So whether the 15 percent screen alone is barring an applicant from interconnecting at a particular site may not be always the complete answer. There might be, as the utility works through the Fast Track questions, other technical issues that prevent it from coming online.

So although this panel is focused on the 15 percent screen and the new potential backup to it, there are technical issues at the same time. Right alongside that is the question of writing out, is the matter of writing out specifically what those questions are.

I'm using our Rule 21 new proposed framework as a cheat sheet here. But the point is for transparency and predictability, as Mr. Lenox just said, the point is to write the questions down, so that developers know exactly what's being asked and what the technical issues are that could send their project from initial review to supplemental review, and then potentially from supplemental review into detailed study.

MS. KERR: Mr. Carranza.

MR. CARRANZA: Yeah. I just want to take Rachel's point and clarify or add that in addition to the penetration screen that's put in place, we also have got to be considerate of the reliability and power quality screens that look at the 100 percent penetration issue on a line section.

So we've got to be considerate of that when we're considering, you know, exceeding the 15 percent limit or the two megawatt limit.

MS. KERR: So just to follow up, you had said earlier that there are some locations that can't even go up to 15 percent.

MR. CARRANZA: Uh-huh.

MS. KERR: Are those, are there technical issues that you're referring to?

(Laughter.)

MR. CARRANZA: Location of the interconnection is very critical. If you are interconnecting close to a substation, where we have plenty of capacity, many times it's not an issue. If you are connecting your project 15 miles out, away from the substation, where we have small wire, the size becomes really critical of your interconnection project.

If it's 100 kW, we may be able to accept it. If it's one megawatt, I can tell you it's going to be difficult.

MS. KERR: Okay, thank you. Mr. Triplett.

MR. TRIPLETT: Thank you. I'd like to thank Ms. Peterson for her comments, because we're talking about the one screen here, the 15 percent penetration screen.

But in reality, we really ought to be looking at all the screens, because it's not just the 15 percent screen that triggers these studies. I'll speak from a little different perspective representing the Rural Electric Cooperatives. All of our systems are rural.

Very long lines, smaller wire, higher impedance systems, by design to just service the load that's required. So the 15 percent screen for a rural electric cooperative is not the only screen that gets triggered very regularly.

So there are, as has been mentioned by several other utilities here, a number of technical issues that come about with these smaller systems, that are very rural long lines that have to be addressed. So we really need to be thinking about the whole process, not just one screen.

MS. KERR: Mr. Coddington.

MR. CODDINGTON: Thank you. I just wanted to address a number of the comments that have been made over the last few minutes regarding some of the examples of circuits where even penetration levels lower than 15 percent present trouble. I agree, that that's certainly a possibility.

I think that actually highlights one of the reasons why using actual, minimum daytime load data is more beneficial than estimating it based on 15 percent of peak data. I mean I think that actually spells out a really good reason if the data is available, if that information can be measured or estimated, but that is a more useful number.

And certainly there are issues with location which create other constraints. Some of the more rural circuits are certainly good examples of where trouble may lie. But again, if you use 15 percent of the minimum daytime load of a line section, some of these problems, I would hope, would be mitigated before they come about.

Because the utilities are right. They're the ones responsible when troubles come down the road, and we do need to maintain a safe, reliable and cost-effective electric system, and that's clearly the lifeblood of our economy. So we want to maintain that.

Again, I'd just reiterate that using actual minimum daytime load data seems like a better way to sharpen our pencil, and rather than estimating this, because effectively 15 percent is just estimating a portion of what minimum daytime load is. Thank you.

MS. KERR: Arnie?

MR. QUINN: Just to follow up on that. So I think we heard that, from Mr. Carranza, that potentially the 15 percent screen doesn't work for all situations, and you've, Mr. Coddington, indicated that potentially that's because of the screen being based on something other than actual minimum load data.

Is that, do people agree that that's the primary issue, or are there other parts of the Fast Track process, other parts of the screen process that are also not kind of working well, that would lead to 15 percent being the wrong number for some feeders?

Maybe I'll put it a different way. If something gets through the 15 percent screen, why isn't it failing one of the other Fast Track screens, to identify that that area or that location isn't a good Fast Track location?

MR. CODDINGTON: If I could make one comment, and I think that's a great question. What I think we've heard are several anecdotal cases of where the 15 percent screen failed, and as one example, I think Mr. Steffel mentioned that they had, they used the 15 percent, and they actually had reverse power flow anyway, and that they had high voltage, which resulted in customer equipment being damaged, which is certainly a concern for all utilities.

I think again in these anecdotal examples that were given, had the utility looked at that minimum daytime load, at least in these examples, that may have actually failed that screen, and gone on for supplemental review, and that system may not have been allowed, or they may have been mitigating measures, like reverse, you know, bidirectional voltage regulation, which is available, might have been deployed.

But in the case of just using this 15 percent screen, at least in the examples we've heard, the utility had some problems. So I guess I would just submit that there are examples where the 15 percent screen doesn't really do the job that it needs to, but in most cases, it's probably catching systems that need to go on for supplemental review.

MS. KERR: Okay. Mr. Carranza and then Mr. Sheehan.

MR. CARRANZA: Just let me add, again, that the 100 percent minimum load of line section is not available all the time. So we fall back to the 15 percent rule. So that may have been the situation here that we're discussing.

In addition, there are other ways to get into the supplemental review. NEM also can go down in that direction, which came past all the rules eventually, and get into supplemental. But let me add one more thing.

As I mentioned in my opening statements, we may have load today in a particular section. But over time, load may change. A particular customer may shut down their business and load disappears. The 15 percent may allow generation to be attached at the time that it was studied. But when that load disappears, now you get backflow and potential issues. So that's something you've got to really be aware of.

MR. SHEEHAN: Just a point of reference. I did a report for solar ABC's, reviewing the FERC SGIP screens with the IEEE members, 1547.6 and .8. We reviewed all the screens for which ones were problematic and which ones were of concern.

And traditionally, the 15 percent is considered to be the one that's most, that trips up the most. The other one is a line configuration one. There's a lot of issues related to subtransmission, which we have not really talked about this panel.

But I think that's a discussion, ripe for this discussion, especially the way Southern California runs its system and the subtransmission, the way it's networked versus the way it could be a radial subtransmission.

So there's other issues that are on the table, that sort of need to be looked at, that are beyond this 15 percent screen. So if you -- we think it's open for a bigger discussion. But this discussion this morning was just on the 15 percent screen, and I want to make sure that everybody understands there are a lot of other screens or need to update that.

The original 2005 order suggested every two years that this be revisited, and this has not been revisited since the 2005 order. So I think it's important to recognize other screens do trip up, but the one that's the most sort of common is the 15 percent.

MS. KERR: Tom.

MR. DAUTEL: In cases where load changes, is there someone who can help me understand what happens after that happens? Is additional equipment put in? Is the interconnection impacted or what's the scenario?

MS. KERR: Mr. Carranza.

MR. CARRANZA: Potentially, the utilities have to fix the problem. We may need to reconductor, we may need to employs several different strategies to fix the problem.

MS. KERR: And I assume the problem would be the same, whether you've used a 15 percent screen or 100 percent minimum screen?

MR. CARRANZA: That's right.

MS. KERR: Okay.

MR. DAUTEL: And real quick, do you usually know about it ahead of time, because there's a load that's dropped of that you're aware of, or is it more kind of you notice the effects of it?

MR. CARRANZA: It depends, it depends. Sometimes we're aware of it and sometimes we become aware of it, because our customers begin complaining of potential issues, or issues that they're seeing with reliability.

MS. KERR: Okay. Mr. Coddington, I think you've had yours up the longest.

MR. CODDINGTON: Thank you. I've got just a couple of comments, and I think one addressed yours, Tom, and my own experience of 20 years in the utility business, in that load data is historical. So you look at load data and there is no guarantee that that is what a feeder or a line section is going to do.

As a matter of fact, you're pretty much guaranteed it's going to be different than that historical profile. I think the utilities use it. It's the best tool you can to estimate what the future may be.

But it's an excellent question, and it's a concern that I share with the utilities here, that if load goes away and that presents a problem, that is on the utility's shoulders.

But I would say I just wanted to address another comment. This comes up pretty regularly. But there was a comment that the load data on a line section for minimum load is not available, or it's just load data on a line section, period, is not available.

So my question is well then how do you come up with a 15 percent of that line section? I mean there are ways to estimate it. There are ways to measure it. I'm saying there are ways to do it, but the comment came up that that load data at a line section is not available.

Clearly, it must be available, at least to determine what that peak number is, so that you can take 15 percent of peak. So I would just challenge that assertion, that the data's not available or somehow, there's no way to estimate that.

MS. KERR: Yeah. Along those lines, I had a follow-up question for Mr. Sheehan. You had mentioned that SMUD is doing something that sounded different, I guess, than what other utilities are doing, the measurement of minimum load.

MR. SHEEHAN: I wouldn't say it's different, in a sense. But I'm saying they've already gone to the 100 percent of minimum load threshold already. So not very many utilities have gone that direction yet. So they're already at that level.

But one of their practices that they do is to put out a meter on the line, to measure kind of the affected area that they think is going to happen, and they download that data and estimate what they think should have been the load, based on their calculations.

So they do a calibration between the estimated and as Michael Coddington pointed out, the real load that's going on on the system. So they're measuring those two to see how close they are, and get more confidence and more sense of the lower their risk level and threat to going backfeeding or having a problem.

Again, I think this issue of backfeeding is really the loss of voltage control is what the utilities are concerned about.

MS. KERR: Okay. If the other three folks who have their name tags up could real quickly address this, and then we'll move on. Mr. Roughan.

MR. ROUGHAN: Uh yeah. I wasn't going to talk to that.

COURT REPORTER: Your microphone.

MR. ROUGHAN: Oh, I'm sorry. It was more of the fact that, you know, once you've agreed to a minimum load, you've completely lost all your flexibility for rearrangement of the circuits. You know, even though many states have goals to reduce load growth to zero through efficiency programs and everything else, the reality is everyone likes their gadgets. Load continues to grow.

So when you go to put a new substation in, typically what you're doing is you're offloading different circuits around, because now you have new source to serve the load.

So once you're stuck with a minimum load number, you're stuck. You can't rearrange it anymore. You now don't have the flexibility on your system, both during planned upgrades, which is a new substation, and during unplanned storms and reliability considerations.

I mean as mentioned by Jeff prior, we strive to only load our systems to 50 to 60 percent of the circuit rating, so that we can move loads around during outage conditions, so we get as many people back as possible.

So when you now set up that on that circuit, you need X megawatts of minimum load because you've allowed so much solar on it, you're stuck with it going forward.

That's the concern about the future flexibility, and frankly the cost of the distribution system, because once you're stuck, as Jose mentioned, you've got to reconduct, you've got to do this, you've got to do that. Because once the system's online, you have very limited ability to require, and in many cases no ability to require that end use customer, developer or solar farm owner, to pay for any changes or upgrades at that point.

Because they're online, they've signed an agreement with you. You've agreed that they can run the way they are. So going back asking them for additional funds to do something different is just not -- just doesn't occur.

MS. KERR: Would having additional DG, distributed generation on a line in some ways give you flexibility?

MR. ROUGHAN: Well, there's two problems with -- well, you know, also in many cases, unless it's a multiple megawatt project, we have records on our GIS of all the generation and nameplate ratings. But what we don't have any transparency to is how much of the DG was actually operating during that peak hour that we saw either the peak load or the minimum load.

So we have no -- all's we're seeing at that breaker or substation or recloser online is the net power flow through that device. We have no idea, unless we have larger projects where we have to have control and equipment to understand what it's doing, because it's so large.

We may know that nameplate rating is 1-1/2 megawatts on that circuit, besides the three megawatts of large projects. But we have no concept, from a transparency perspective, how much of the 1-1/2 megawatts is actually still operating.

We can see what the big project is doing at our peak or minimum, but we don't have any transparency into what those individual units are.

I mean as we all move into the advanced meters and Smart Grid and all the rest, we will get that transparency. But most of us simply don't have that today to understand that. So that's the other difficulty of using simply a peak load or a minimum load value, is that you don't -- it's a net power number. It's not -- it's the load on the circuit less any generation that's actually running at that particular hour.

MS. KERR: Thank you. Is to a good time for you to follow-up? Okay. Mr. Steffel.

MR. STEFFEL: Okay. I'll try to move through quickly.

COURT REPORTER: Microphone.

MR. STEFFEL: Oh. You asked a question about where could the 15 percent screen fail. I think we've given an example, plus mentioned other types of circuits with load profile anomalies. Now that's the very, you know, that's rare, but it does occur.

One of the issues is protective zones versus voltage regulation zones, and at the beginning of the voltage regulation zone, you're going to have a voltage regulator. Not all of them are reversible; some of them are older and we'd have to change if you're going to have reverse flow.

Number two, even if they are reversible, if they're not set correctly, they can also operate incorrectly. So you can have something meet the 15 percent criteria for a protection zone, but not a voltage regulation zone.

If you look in the material, you know, we gave you, there is four voltage regulation zones on the rural feeder that I mentioned had a 3.3 percent minimum hosting capacity. So what did we do in that case, where we had that problem? We had to reconfigure the circuit and the substation.

So just like Tim mention, that does limit our ability to reconfigure again. We've now reconfigured to handle that problem.

Another impact is on distribution automation, and this is where we're developing automatic sectionalizing and restoration schemes across the board.

We have some circuits that have three megawatts of PV, and what happens when you have a fault? PV disappears. That was three megawatts, and our system thought that the load was three megawatts less on an automatic scheme.

But then when it picks up the load, there's three more megawatts, and then five minutes later, there's three less megawatts. So the voltage regulation and everything changes. We've actually had to block some schemes. So does it impact reliability? Yes. I mean that's a clear indication.

On load data, new systems that went in since the reading that you had of your load measurement, whether it's minimum or peak or whatever, effect it. The contribution that the systems, that were on the system, and Tim mentioned that to the load reading.

I mean it could be that you had a cloudy day, the day of your minimum load or peak load or whatever, or it might have been a clear day, and then maybe the systems are deteriorating or not online. Then you've got pending systems that you've got to also account for, even if you do look at these load measurements that you have.

Then there has to be a buffer for inaccuracies. You've got load imbalance, you've got phase imbalances and other types of things that are going to trigger things on the circuit. So you can't just go up to 100 percent minimum load and think that's a great screen. There has to be a buffer, or else you're going to still end up with a lot of problems.

MS. KERR: Okay. That's a good segue to our next question. So we've heard from SEIA and other commenters that the 15 percent screen's a problem. We've heard from some of the panelists today that 100 percent minimum load screen may be a problem.

Are there other things we should look at? If there are problems with both of those, are there alternatives that we should consider, to keeping people, generators in the Fast Track process? Oh, Mr. Triplett.

MR. TRIPLETT: Well, I think that's a great question, and that's ultimately the question of the day. I think that there are things that should be considered, and as I mentioned earlier, there are working groups that are considering these things right now, the 1547 working groups.

Those working groups are comprised not only of representatives from the utility industry, but also representatives from the manufacturers of equipment that are interconnecting with distribution systems, and the developers and the generation interconnectors themselves.

I think that's really the appropriate forum where these things should be discussed, from a technical nature. How effective are the existing screens, and what can be done to make them more effective?

At the end of the day, most generation interconnection requests can be accommodated. It's just a matter of does a study need to be done? Does there need to be any mitigation techniques to accommodate that, or can it just be done, reasonably assured that there will be no safety and reliability concerns to a Fast Track process.

So I think those working groups, in my opinion, the stakeholders should consider allowing that process to go through and answer those questions exactly.

MS. KERR: Thank you. Ms. Peterson.

MS. PETERSON: Having been through eight months of settlement discussions about the screen and a number of other issues, I guess I would --

I would tout the 100 percent of minimum load backup screen within supplemental review, with the attendant means of calculating, measuring, determining, etcetera, as really one of the best steps forward that can be taken at present, before you get to the much more indepth technical advances that I believe are coming, and as Mr. Triplett said, are coming from places like the IEEE 1547 working group.

If an advance is being pursued in terms of expanding Fast Track, and remaining within a certain zone of safety and reliability, then I think that these screens, although they, as everyone notes, they do have their flaws, are the best present-day step forward. Other long term approaches are exactly that; they're longer-term.

MS. KERR: Thank you. Mr. Sheehan.

MR. SHEEHAN: Just to capture that in another way, we believe that above the 15 percent is really one of the key issues we want to address, and the supplemental review, which is already in the FERC 2005 Order, and it's in Hawaii Rule 14(h) and California Rule 21, that's really the venue we think is the best, a great approach to sort of get to the next level, without going through a detailed study and getting into a lot more.

It's again, using utilities basically N, O and P in Rule 21, the penetration screen, the power and quality, reliability and voltage fluctuation, the safety and reliability issues, those issues need to be addressed.

Doing it in the supplemental fast process really addresses, we think, the key issue, that for those projects that you can get through a lot faster, instead of going through a full study process and getting caught in that full study process.

Because that's the time and in a lot of cases, that's really where the hang up is. We can get a lot more of those projects that are closer in, that everybody agrees can go a lot faster, and doesn't need that full monte study.

MS. KERR: Mr. Steffel.

MR. STEFFEL: PEPCO Holdings, Inc. is taking another approach to this, and what we're working on is acquiring a semi-automated study tool that will operate in a time series load flow, and can operate quick enough to respond within the 15 days, so we can actually do this study in-house.

We're moving ahead with it. I mean it promises to be fast. All the testing we've done indicates that. Right now, we currently for any system that's over 250 kW, we do a static load flow anyways. So this would just be an extension to actually doing a time series that looks throughout the whole year, and actually pulls in the solar data.

It actually will be a little less conservative to allow larger systems. It would give back a much more detailed feedback to us, and actually give us the true impact on our system. The tool would also continue to look at aggregated type of impacts up and down the T&T system.

So it would also incorporate pending, and it would incorporate things that have gone in. So it eliminates some of the problems we've mentioned with load measurements, and trying to adjust them for things that have come on the system, things that are pending and so on.

MR. QUINN: Can I just ask a follow up on the -- it seems that there might be a consensus, that everyone agrees that some sort of supplemental study should be allowed.

There should be some option for the interconnection customer to do some sort of supplemental review if they failed the Fast Track screens, but would prevent them from having to go through a, you know, full-blown long, costly study. Is that consensus there? Does everyone agree with that general principle or statement?

MS. KERR: Mr. Singh.

MR. SINGH: Yes. I guess --

COURT REPORTER: Your mic.

MR. SINGH: Sorry. We just don't know what that supplemental study looks like utility by utility also. So I don't want to complicate the question, because you asked what seems like a simple question. It's the Wild West out there in a sense, and again we're all dealing with the new market and such.

But we do not see consistency across utilities and how they're treating DG. We do not see consistency in standards. We do not see consistency in processes. We do not see consistency in what it actually costs. We do not see consistency in what we're being asked to do.

I understand the leaning towards extreme conservatism among utility distribution and transmission engineers. You don't get a bonus, in a sense, by handling more DG. You just get fired if there's a reliability event. I understand that. I used to work for a utility.

But we have states, New Jersey just passed legislation that is accelerating its solar mandate. States want to do solar and there's annual requirements.

Study sounds nice, but we're going to wait two years to come up with revisiting the standard through IEEE, and then we're going to spend a couple more years with more study on projects, and states are saying we want solar right now.

There's a real disconnect between the immediacy of the issue there, based upon what states and their legislatures and governors have decided what is important, versus some of the tones of discussion here about let's keep on studying this.

We might be a little more comfortable with some of that tendency if we understood what the study process was, and all of those other issues that I raised. But that's not what we're seeing here. So sorry for a little bit of the opining there also, but you asked a simple question.

We don't know what that study process looks like utility by utility. So that creates a huge problem.

MS. KERR: Mr. Roughan.

MR. ROUGHAN: I think we continue to concentrate on what the utility can and what the utility cannot do, and I think there is significant responsibility from the solar community to also help us understand what they can and can't do. The dilemma we have here is the intermittency of the projects.

On an hour by hour, minute by minute issue with cloud cover, on a month by month level, just because of the radiation changes over the course of the year. So we're being asked to answer a question that doesn't have a simple answer, and we're being asked to do it through screens and do it quickly and get these online fast.

What I fail to see is the need for a two-way street here, to have the solar community be able to provide to the utility some sort of certainty as to what their project can and cannot do. It's all that the utility needs to do this because of all these good reasons, but there are just virtually no quid pro quos from the solar community.

For example, if a customer really wants to go through the Fast Track process, really doesn't want to deal with detailed review, there's a relatively simple way at that. There's a relatively simple way if they manage the input of the solar project to certain levels at certain times of the year, and we have some control over that, over the management of the output and the solar array, to make sure it doesn't impact our system.

Then they can live within what they're doing. There may be certain hours of the year where they have to be cut back, perhaps in terms of output. But again, really what's not happening is any work to try to manage the intermittency of this resource. If there was additional work there, and I think that's what Jeff really talks to this, in terms of what the IEEE working group will and can do.

By bringing up ideas in those types of groups, they can be vetted and fleshed out as to what works and what doesn't work. But simply controlling the output of the solar project for certain hours of the year may well make these things easier to manage on the utility distribution system.

Putting some responsibility, instead of just simply having -- the utilities have to absorb whatever they do whenever they do it.

MS. KERR: I'm curious as to what you're seeing, Mr. Lenox, if you have a reaction to that, and then I'm also curious if there is equipment that would make that relatively easy to do?

MR. LENOX: So my reaction to that is that, you know, those, I think are options if you're failing screens, and there's both technical and economic implications to those measures, those measures that exist. But we don't want -- and they're evolving over time as technology advances.

But I think we do need to keep in mind we are talking about making changes in a relatively short term to accommodate the very fast growth of the industry, versus the longer term process that is being driven, the 1547 process at some more venues. But that is, you know, it's really too far out to address the issue we're trying to address here.

We do need to have a process so that we can study these projects in an appropriately expedited fashion, so we can get technically viable projects online. That's the bottom line. We're not talking about putting projects online that are going to significantly impact the reliability or safety.

That's not what we're trying to do. We're not trying to degrade the reliability of the utility system. We have a model here that we are looking at, that accomplishes that. So the question really isn't is there a bunch of things that the PV industry can do to mitigate this, that or the other impact.

The question is, is there a way for us to decide that a project is not going to have an impact, in a manner that is consistent with the reliability, but also consistent with policy goals and with commercial realities. If we get outside of that space, then we can start to talk about well, here we have, here's a project we want to do.

It's failed this screen or that screen. What are the mitigations we can put in place and the solar industry, I think, in general is very open to having that discussion and we do have that discussion on a project-by-project basis.

MS. KERR: Thank you. Mr. Sheehan.

MR. SHEEHAN: I would like to avoid the discussion, but since it's been brought up, I think energy storage is off topic, as far as I'm concerned, for this discussion here. It clearly is not something that we've been asked to talk about, because it's beyond --

We've really been focused on the time and the amount of money it costs to do interconnections of greater than 15 percent. If we get into the issue of storage, that's well beyond kind of where we want to be at this today. I just want to take that off the table.

MS. KERR: Mr. Roughan.

MR. ROUGHAN: Yeah, and I guess I'm not -- (a), yes equipment is available to -- I mean they've got this inverter control software that can easily be throttled back up and down as much, whatever you want to do. That's very simple to do.

So the reality that that can occur, I'm just suggesting that that be part of the discussion as well, instead of simply what is the utility's requirements and what can they do and what can they not do. Where the bulk of these projects are interconnected is under the jurisdiction of the state regulatory bodies, who give the approval for the distribution utilities for their recovery and for their capital plans every year.

We're talking about significantly potentially impacting those agreements that are either in place or have been talked about. I mean the planning process for a utility, we have projects that are planned out three, five, ten years out that are in-process and being approved now and pulling together resources for.

You know, juggling that and changing that around because of solar projects could make that much more inefficient. But it's just another idea here that is, I think, worthy of a discussion, because ultimately to take advantage of the fast solar growth, that can and will potentially put reliability at risk, simply by a rule that says if it passes this, you have to do X, Y and Z, and you don't have authority to do anything more, I think does risk reliability in the short term.

By managing the process and studying it the way it needs to be done, we can come up with a much better process for utilities and for solar developers and for society as a whole.

MS. KERR: Mr. Coddington.

MR. CODDINGTON: First, I just want to say that I think Mr. Roughan brings up an excellent question, although I think it's really off topic for this question surrounding screens and 50 percent. But if since the question was raised, if I could give my own perspective on a couple of these topics.

I think the solar industry and especially the inverter industry, and along with standards groups and national labs that have been mentioned today, are working on many solutions to make these systems more grid-friendly, to be better utility partners, to behave themselves in a more traditional way, to act more like utility generation that has been online for, you know, over 100 years.

So I think that we're moving that way, and some of the standards efforts, especially the IEEE 1547 groups, are working to find ways to deploy some of these advanced functions that I think really will make our future look much better in this whole discussion area.

I did want to just touch on IEEE 1547. It's been mentioned a few times, and I'm not really sure that that group is going to address screens to anyone's satisfaction for this discussion this morning. But I do believe that the 1547.8 working group will address ways to deploy some of these advanced functions, to again address Mr. Roughan's reasonable concerns. Thank you.

MS. KERR: Thanh?

MR. LUONG: I guess I had a question regarding the IEEE working group. How far does it come out with a resolution?

MR. CODDINGTON: So if I could, since I was secretary of IEEE 1547.6 for Secondary Networks, a little off from some of the other working groups. We actually have a chairman of one of the current working groups in the room today, Mr. Saint with NRECA, working on 1547.7, which is the supplemental study group.

There's another active standard being developed, and it's 1547.8, which I think is what most of the references have been aimed at today. That's really an advanced, you know, really a focus on higher penetration, some of the new advanced functions that are being, that are available today.

But how do we deploy these? How do we act put them into use? To answer your question, I think that over roughly the next year, that would just be -- no one really knows when a standard is going to be completed and available. But it looks like, you know, within the next year, that 1574.8 should go to ballot, and then hopefully within a few months after that it may be voted in as a standard.

The standard for interconnection, adopted by FERC and many states, 1547, that's the interconnection standard, was approved just a few years ago, 2008. But you know, there is discussion now about revisiting the interconnection standard, and looking at ways to perhaps integrate low voltage ride-through, low frequency ride-through.

Those functions are being discussed, as well as volt bar control, some of the things that again may make this technology more utility-friendly, and to be able to mitigate perhaps some of these variability concerns that the utilities have raised today. I hope I answered your question.

MS. KERR: Okay. We're actually sort of running out of time. I'm going to move along a bit. So assuming there should be additional review screens in the Fast Track process, should these additional review screens be different based on the operating characteristics of the different types of generators, and what types of generators should have different screens? Mr. Coddington.

MR. CODDINGTON: If I could just make a short statement. Yes, I do believe that any kind of technology with power electronic inverters on the front end should be treated differently. The engineers in the room know that traditional generator synchronous machines have greatly different characteristics.

They're of, I would say, greater concern for interconnecting onto the distribution system, whereas inverter-based systems generally behave themselves in a much more predictable way, and are inherently safer in nature.

MS. KERR: Ms. Peterson.

MS. PETERSON: Yeah. I'll just answer by identifying some of the policy guiding Rule 21 in California. The California Public Utilities Commission has long said that the interconnection tariff, Rule 21, shall be technology-neutral, and that was the guiding principle that the settling parties stayed within in developing the reforms to Rule 21.

So as a result, the screens in the Fast Track process identify the potential different technical issues that different types of generators might trigger. So a synchronous generator might trigger a different screen from an inverter-based generator.

The one place where the settling parties proposed a slight difference is in the measurement of minimum load for solar PV in that one screen for 100 percent of minimum load. The solar PV measurement of minimum load is based on daytime hours, and for all other forms of generating technology, it's absolute minimum load.

MS. KERR: Mr. Triplett.

MR. TRIPLETT: You bring up a good point. Certainly, different types of generation have different impacts on the system. But I think ultimately, it's not the type of generation but the impact seen. So I think the technical screens should still be broad in nature, looking at things like fault current and impacts on voltage regulation, rather than specifically saying inverter-based, induction, synchronous, so on and so forth machines would have these separate rules.

So I think the rules need to be global, because ultimately it's the impact on the system. We don't care if it's an induction machine or an inverter-based machine or a synchronous machine causing voltage concerns on the system. We just care that we have voltage concerns on the system.

So the screens should still be based upon the root concern, not the generation type.

MS. KERR: So if again, assume that a minimum load screen would be effective as an additional review screen, and by effective, I guess I mean that it would decrease interconnection costs for distributed generation without compromising safety and reliability.

How would such a load -- how would such a screen be structured? For example, is 100 percent the appropriate minimum? In the California process, were other percentages discussed? Are there other issues based around that percentage that we should know about?

MS. BRYANT: Specifically earlier, Mr. Steffel said --

COURT REPORTER: Microphone, please.

MS. BRYANT: It's on. Is it on? Okay. Mr. Steffel said earlier that you thought the 100 percent minimum daytime screen was perhaps not good enough, because there wasn't a built-in buffer. So if that number was reached, then what would happen at that point, and what reliability implications would we incur, I guess, if we let the 100 percent go through.

So I guess in addition to the rest of the panelists, specifically for you, is there a number that's around 100 percent that you would be comfortable with, or what sort of buffer numerically or otherwise do you think is necessary?

MR. STEFFEL: Well, the buffer would need to take into account the inaccuracies of your estimation. It would need to take into account the possibilities of load change and load profile change. We talked about, you know, the possibility of industries not working on the weekend, where they had been running seven days a week.

It needs to take into account on balance on system, which can change. So one of your phases, if it's going to get the reverse flow on it, may be the minimum load of that. You've got to make sure you've got the minimum load phase, not just your average.

You've got the operation of the existing PVs in that section that you've got to account for, and the variation from year to year, and then you've got -- you've got to take into account what the pending ones' impact will be.

So the thing, and many utilities aren't collecting that data right now. So if we do have it available, we put it, move it down from a whole feeder down to a section. You've got to take in all those accounts, and all I'm saying is you need a buffer.

You can't just go right up to 100 percent minimum load, and allow something to go through where you haven'+t checked a voltage regulation devices to see if they're going to have problems in reverse flow and other types of things. So that's a problem.

Then when you have a single feeder on a

distribution transformer at a substation, protection folks would want transfer trip on a system that could actually backfeed into the transmission system.

So there's a number of things that have to be looked at, and if you go right up to 100 percent of your minimum load, daytime load, you're just not allowing yourself a buffer.

One of the other things I was going to mention before is we have almost no control, monitoring or control, over most of the systems out there. If they're on, we have to send someone out there if there's a problem to turn them off. Yes, the very largest ones we do have monitoring and remote possibility of disconnect.

But you know, the vast majority of them are going to operate until someone actually goes out there. A lot of times, the places are closed. Nobody's there. They're operating totally on their own.

So you know, if we push everything right to its limit without any control, and just to give you an example, the IEEE 1547 recommended that there be monitoring control at 250 kW and above.

Well, at the state levels, we've been restricted. We can't put anything over, anything that's two megawatts and below can't have monitoring controls. So you've got a tremendous amount of the solar out there has no control from any central point. So you have to consider all that when you make these screens and go right up to certain limits.

MS. KERR: Mr. Coddington.

MR. CODDINGTON: Thank you. Just to address that last comment and make a couple of other statements, IEEE 1547 actually requires provisions for monitoring of systems over 250 kW, and it's certainly not mandatory. But provisions need to be in there, and I agree with Mr. Steffel, that having that kind of monitoring and control could be very useful for the utility.

But there's another assumption that seems to be inherent, that exceeding 100 percent of that minimum load is going to be problematic. Indeed, in some cases it may. There may be high voltage. There may be equipment damage. But there are certainly systems out there that are designed to work well over 100 percent of the minimum load on a distribution feeder.

That's the exception, but I just wanted to clarify that there's no hard and fast ceiling, that 100 percent of minimum daytime load would cause a system to fail. I'm not recommending it. I'm just saying there are systems out there and it should be noted.

But the question at hand has come up twice. The question was is there a ratio that would be acceptable, and I think the two ratios on the table now are what do we have today, and that's 15 percent, which is equivalently 50 percent of minimum load. By the derivation of this whole process, we're defining 30 percent of peak load as being the defined minimum, and then you take half of that, 50 percent, and that's what the utilities are acceptable with today.

And then you've got, on the other side, some utilities in California looking at 100 percent of minimum daytime load. So I just would assert, for discussion, that we're somewhere in that range of 50 percent to 100 percent of minimum daytime load, and that would be, I guess, the area of discussion to perhaps settle that, or at least to talk about.

MS. KERR: Mr. Steffel.

MR. STEFFEL: Yeah. We have no disagreement that systems can be made to take backfeed, and we have backfeed. We have backfeed on feeders, we have backfeed on transformers. But the problem is they need to go through a detailed study, so that you do the appropriate modifications to the system.

So that's the only thing I'm saying. On a screen that's going to allow something to go through, you've got to be really cautious. The screen needs to be conservative. I mean we can accommodate those things, but you need to do the detailed study, find out what has to be done to upgrade the system to handle that.

MS. KERR: Thank you. Mr. Carranza.

MR. CARRANZA: You've got to be careful when you're talking about exceeding 100 percent minimum load. For example, let's say you exceed 100 percent minimum load in our system on one of our circuits.

The topology of our system is such that we have load tap changers that control the voltage that feed four, up to eight circuits at a time. You start pushing too much current back through that bus and out the LTC and into the transmission, what the LTC or load tap changer does is it lowers the voltage, thinking that there's lower load on the system, therefore keeping the voltage within limits.

When we start pushing too much current back through the LTC, back to the transmission, the reliability issue we experience is low voltage on the circuits that don't have PV or minimal PV on them. So as you mentioned, yes it could be, but we've got to be very careful when we're doing those type of studies.

MS. KERR: Mr. Sheehan.

MR. SHEEHAN: Thank you. I just want to go through a typical approach, and I use this "typical," because this is -- most utilities use nameplates. So when they get information from PV developers, they usually use the DC nameplate.

Well that's DC, it's not AC. So there is inherently a buffer in there of 15 to 20 percent, because that DC rating isn't the same thing as an AC equivalent. So this issue of being right up that 100 percent minimum load is something I think you need to be very well aware of.

Typically, we went through this discussion before, and that's why I think the approach that SMUD has taken was to do the calculation and then do the measurement, is really kind of what we want to get back to, to give that comfort level and to understand the risk.

This idea that you're going to be running up against the reliability issues, I think you need to be at least aware that there are better ways of measuring it and calculating. Traditionally, U.S. utilities do a lot of calculations. Europeans do a lot more measurement systems.

I think what SMUD has done is tried to measure the best, or bring together the best of those two practices, and trying to give some sort of comfort to what they're doing, because they're pioneering in this whole effort, and I think we need to be capturing those pioneering efforts.

MS. KERR: Ms. Peterson.

MS. PETERSON: Yes. I'll just list some of the additional buffers that are proposed within Rule 21, alongside the 100 percent minimum load screen.

There are two additional screens in supplemental review related to power quality and voltage fluctuation, allowing the utility engineer the chance to satisfy themselves that the interconnection of that particular facility will not exceed some of the limits that are set in other electric tariffs by the CPUC, for example.

Another form of buffer is what it takes to get into supplemental review. The settling parties raised the fee for supplemental review from $600 to $2,500 and the tariff allows 20 business days for the utility to complete the supplemental review process. So all those are forms of providing the utility engineer the opportunity to assure themselves that 100 percent of minimum load is a viable generating capacity limit.

MS. KERR: Go ahead.

MR. DAUTEL: Real quick, especially as we get back to the utilities. I don't feel like I have a good sense for what the utilities' position on Mr. Coddington's kind of translation of 15 percent screening to a 50 percent minimum load screen. Do you guys accept that, or are -- do you have concerns with that kind of logic?

MS. KERR: Mr. Roughan.

MR. ROUGHAN: Frankly, I think it's a little premature to suggest that, on a comment by Mr. Coddington a few minutes ago, whether we can accept it or not. I mean we do want to review that. I mean it's worth -- it absolutely is -- he's absolutely correct about the derivation of the 15 percent. We all accept that.

I think ultimately we really need some time to kind of think through that, whether that's an acceptable number or not. I think we'll still run up against what we're hearing from most of the other parties, that in many cases, with tens of thousands of line sections, the data, the measured data is not available.

MR. DAUTEL: I mean this assumes data is available obviously, or that you can get it through some process.

MR. ROUGHAN: Yeah, and again, the reason I'm just hesitating a tad is my prior statement about the net power that we're actually seeing at our substation breakers and reclosers, right? It's a net of the load on the circuit, less any DG that we don't have monitoring data available for.

As Steve mentioned, New Jersey, they don't know anything less than two megawatts. They know the nameplate, they know where it is. But they don't really know if it's operating or not, and they don't have any detail at the peak hour of the feeder or the minimum load hour of the feeder, what that particular generator was doing.

I think that's the real key here, is that if we had all these pieces of information, it would be really simple. We could say yeah, whatever percent of minimum load is perfect, right. But there's a lot of pieces of information that just aren't today available, but eventually will become available to us.

MR. DAUTEL: I see what you're saying, but I don't see why that puts any additional uncertainty into the minimum load comparison that wasn't already in the comparison to peak load.

MR. ROUGHAN: Well ultimately, even with that 50 percent peak load value, there was always a way the utilities could look at that and say yes, it's good to go.

It made it through the screens, or say because of, you know, the supplemental screens the California Rule 21 proceeding put together are other screens that utilities did anyway.

Every project, it's not just does it pass the screen, it's good to go; it's you go through the screens and then kind of look at what else is there, double-check what else is really going on in the area, you know, future plans for abandoning an old substation, future plans for upgrades.

There's lots of other things that the planning engineers are looking at, besides simply was it 14.9 percent of the screen, or was it 15.1 percent. And I do have to disagree with the fact that 15 percent is some sort of magic number that automatically jumps people into a detailed study.

In many cases, there's plenty of ways you can get around the 15 percent if you're over it by a little bit, if you don't have all these other issues in place and the engineers who work the area understand those issues best, and are the best suited to come up with whether that's acceptable to allow it to go online, with simply going through the Fast Track.

MS. KERR: Mr. Singh.

MR. SINGH: Yes. I guess I feel compelled that I've been hearing be careful, double-check, study some more. I get the position from a lot of the utility representatives here. Oh, we haven't figured it out yet. We've got to, you know, it will take some time. You know, it's tough, we've got to be careful. We get that.

In terms of innovation, there was a question earlier about us working with the utility industry. Speaking for a company that's actually owned by electricite de France, that's our parent company, there's a heck of a lot of innovation going on in our company, not only in price, because as has been mentioned, the price of PV has dropped dramatically, but in terms of quality, in terms of high penetration quality.

There's Solar Electric Power Association. They recently had a high penetration PV conference that was well-attended by both developers and utilities. So that dialogue is very much happening, and I'm sure a lot of the utilities here are a part of it. We are.

So I think for FERC staff and Commissioners, to rest assured that innovation is not the challenge here from the IPP side, and we do see some utility engagement on how to make this work. But the tone of just be careful, further study, further study is not going to work in our policy context today.

We can't just study this to death, and the places that are actually making the advancements on this are the places that have assertive policies. Sacramento's been mentioned, the State of California. We have to learn from that and leverage that to come up with better clarity across the country.

MS. KERR: Okay. We have barely touched on the two megawatt Fast Track limit, and we're getting close to lunch. So I would like to shift to that topic. So SEIA has submitted that the two megawatt threshold for eligibility for the Fast Track should be eliminated or increased to ten megawatts.

What would be the consequences, whether it's technical, safety, reliability, administrative, of increasing or eliminating the two megawatt threshold?

Mr. Carranza and then Mr. Lenox.

MR. CARRANZA: Well at least, for instance, you need, the first thing I would point out is the maximum rating that we typically lead our circuits to is 10 megawatts. So automatically when I tell you, unless there is a lot of load on that circuit that can handle the generaton that is being attached, it is not going to go through Fast Track.

Number two, we've been doing this kind of work for several years, and it's our experience that the further you move away from the two megawatt limit, the higher the probability that your project will not pass Fast Track. It's just the reality on our system and where the interconnections are happening.

The interconnections will probably happen faster if they were being developed in areas where the load centers were at, but the reality is that you can't put large PV systems where the load centers are, at least in San Diego, because that's where there's very little land available. And whatever is available is very costly.

So they are looking at going out to our rural areas. And as I mentioned earlier, our rural areas are not designed to carry that type of generation because the load was never designed to be there.

MS. KERR: Mr. Lenox.

MR. LENOX: Yes. You know, the system size cap is in effect just another rule of thumb that is being imposed. And again it currently puts you into this black box scenario.

The other screens that we're looking at all have a specific technical basis. I don't disagree that as you get over a certain size the probability that you won't pass some of the other screens goes up, but it doesn't mean that you should arbitrarily cut off the ability to be assessed under those screens just based on the size line because, as we all agree, every circuit is different, locations on circuits are different, and it's really, you know, a somewhat arbitrary rule of thumb.

MS. KERR: Okay, Mr. Carranza.

MR. CARRANZA: Just a quick response. You may consider that an arbitrary limit, but through experience we have found that if you go--if you move that up to 10 megawatts, let's say, and you want to push everything through Fast Track, you're just going to bottleneck everything. Things just aren't going to flow.

We're going to have to look at the Fast Track and everything from that point on is either going to go into what you fear to be an independent study. It's not going to work.

MS. KERR: Okay. Again, I'm going to keep moving along here. I'm interested, Ms. Peterson, in what deliberation of the Fast Track threshold was there in the Rule 21 proposal?

MS. PETERSON: Extensive deliberation.

(Laughter.)

MS. PETERSON: And honestly, I actually thought that between Mr. Lenox and Mr. Carranza they actually captured the issue quite well.

From the developer perspective, if I can recapitulate, is well let's take a look and see if this point of interconnection happens to be a place, because of these unique characteristics, where the project of X size above that size limit might actually make it through the Fast Track screens.

The utility perspective, if I can restate what Jose just said, is that you want to balance the number of applications into Fast Track so that it remains fast. Right now in the proposed reform, Fast Track should last 15 business days. And there are some technical considerations.

They are different, depending on the design and operation by each utility in their service territory, and so the ultimate compromise that came out of our settlement process established different size limits according to the interconnection voltage of the particular utility service territory. So it's 1.5 megawatts for San Diego Gas & Electric, and 3.0 for both Edison and PG&E up to a 21 kV interconnection.

I should mention that San Diego Gas & Electric has up to 12 kV interconnections in their distribution system.

MS. KERR: Okay. Mr. Roughan.

MR. ROUGHAN: If I could just suggest the fact that the 2 megawatt limit was not an arbitrary figure. It was actually worked out over many, many months in terms of the small gen interconnection proceeding negotiations of 10 years ago.

So the fact of the issues relative to what Jose and Rachel have mentioned about the voltage level you're interconnecting to, the fact that most projects at this megawatt size whether it's 2 or 10, are typically trying to connect to lower distribution voltages purely due to the cost of the interconnection versus connecting to 115,000 volt transmission at much higher cost for all the equipment that you need to buy to interconnect to a higher voltage versus a lower voltage.

So there's a strong desire to be able to interconnect at lower volt distribution. And a megawatt limit based on voltage is a much more accurate representation of what can be done. But the 2 megawatts is not arbitrary. It was a negotiated value in a prior process and potentially could be looked at, or should be looked at again going forward.

MS. KERR: Okay. So it sounds like perhaps a limit based on voltage might be an option? Because, I don't know, it sounds like that's where you ended up. I don't know if there were other options discussed during the settlement process?

MS. PETERSON: There were other options discussed ranging up into much higher megawatt sizes. Yes, we ended up at those size limits also based on the voltage of the interconnection. That just appeared to satisfy the wishes of all concerned.

I will state that the settling parties set out a recommended scope for phase two of our interconnection rulemaking, and they specifically want to revisit those size limits. That's driven by the developer community, that request.

MS. KERR: Okay. So any last comments for this first panel before we break?

(No response.)

MS. KERR: Or from staff?

(No response.)

MS. KERR: Okay, well thank you all for a good discussion. I would like to remind everyone that we are accepting written comments on the topics discussed today until August 16th. So if you want to clarify, or add detail, or even audience members or other members of the public, we encourage comments based on what was discussed here today.

So I would ask that everyone be back a little before 1:00 so we can start the afternoon panels on time. If you need suggestions for lunch, grab a staff member and we would be glad to help you.

There is a cafe at the end of the hallway on this floor in this building.

Thank you.

(Whereupon, at 11:37 o'clock a.m., the conference was recessed for lunch, to reconvene at 1:00 o'clock p.m, this same day.)

A F T E R N O O N   S E S S I O N

(1:05 p.m.)

MS. KERR: Okay. Well, I'll come back for today's afternoon panel. The first panel this afternoon is a panel on collecting and sharing peak and minimum load data.

Our panelists are Bhaskar Ray from Sun Edison on behalf of SEIA; Dan Adamson from SEIA; Kristen Nicole from the Electric Power Research Institute; Roger Salas from Southern California Edison; Steve Steffel from Atlantic City Electric; Tim Roughan from National Grid on behalf of EEI; and Kevin Fox from Keyes, Fox and Wiedman on behalf of the Interstate Renewable Energy Council.

With that, I'd like to invite our first panelist, Bhaskar Ray, to give his opening statement.

MR. RAY: Thank you, Leslie.

COURT REPORTER: Microphone.

MS. KERR: Oh yeah. I forgot to remind everyone.

MR. RAY: Thank you, Leslie, and I appreciate the invitation and on behalf of Sun Edison, I'd like to thank both FERC staff and Commission for the opportunity to speak at the panel today.

I'm Bhaskar Ray, Senior Director of Engineering for Sun Edison, and I manage their interconnection activities there. So with that capacity, I'm here to talk a little bit about what we believe our official position has been, and then I'll definitely do a little bit more deep dive on the load data collection.

So you heard considerable amount of discussion, very fruitful and very productive in the morning panel, that there is a need for updating the FERC Order No. 2006, and that's what we believe at Sun Edison, that the SGIP procedures and the requirements do need the upgrade, because of the change of the circumstances for the solar electric generation interconnections, as we filed with our projects in the U.S. pipeline.

We strongly support SEIA's petition for update the SGIP rules, as they have failed in our ability to keep a pace with the rapid evolution of the solar industry and become barriers to entrants to the wholesale market. Recent experience with certain DG projects have very strongly asserted that process.

The current SGIP rules are an impediment to these renewable projects that we're trying to build and implement, because they're imposing unnecessary cost, prolonged delays and uncertainty in the solar energy development cycle.

The 15 percent rule in particular, we believe, is overly stringent and it triggers significant project delays, and we've had at least four projects that's encountered those delays. You heard a considerable amount of discussion in the morning where 14 parties in California have reached a settlement process for the Rule 21 in CPUC rulemaking as part of the recent reform.

I think that's refreshing in terms of understanding some of the process that went into it. A tremendous amount of work has gone in, which could become a framework for us to consider.

The centerpiece of the settlement, as we all know, is a significantly reform CPUC jurisdictional Rule 21 tariff, that can definitely act as source of ideas for updating te SGIP technical standards nationally.

The national best practice for the distributed generation penetration level has been introduced in that reformed Rule 21, under which the aggregate interconnected generating capacity can be equal to 100 percent of the minimum load on a distribution line section, and I believe SEIA's testimony talks at length about that.

As part of the settlement, the supplemental review screens have also been formalized, which I believe has a lot of merit for consideration, and clarified regarding the issues being addressed by the distribution provider. This is more robust look at site-specific impacts of power flow than the initial 15 percent review screen, as opposed to applying it globally.

Now let me talk a little bit about the whole load data collection process. The ability to determine the minimum circuit load, we believe, is integral to a more effective screening protocol. That is our process, that it would significantly help us when we do feasibility analysis for the research.

We feel that because of lack of enough load data, we're in a black box where we don't have enough transparency and understanding of what the system circuit loading needs to look like.

Although it is not the universal practice of the utilities currently to monitor the minimum load and the time of operation across the majority of their radial circuits, this should not be a barrier to implementation of the solar-specific minimum load screen.

That's what we have talked at length, in terms of understanding that the solar projects should be subjected to the minimum load screen, as opposed to the other technology-specific projects.

Sun Edison also believes that the utilities should be required to collect and provide peak and minimum load data on all circuits, where existing plus planned distributed generation additions would represent 15 percent or more of the circuit peak load to generation developers.

This likely would mean monitoring the load and installing good monitoring devices where they are not available, but we believe that the time has arrived where we need to seriously consider that.

As an alternative, Sun Edison also recommends that where actual minimum load data is not available, powerful software algorithms be extensively used by the utilities, and consultants be hired wherever there's the need for using that expertise and the specialized skills, so that load data can be estimated with reasonable accuracy, based on the old historical load patterns and standard load profiles for various customer classes, that many utilities maintain and update on an annual basis in their database.

Finally, the Sun Edison team feels that there's greater transparency to the load data that should be encouraged, more widespread access to load data, and known system limitations to accommodate any additional distributed generation, will greatly facilitate the developer site selection of investments, streamline or connection review, and enable fast track eligibility.

So let me wrap with some of the recommendations that we believe is what sharing with the panel is. We think a swift SGIP rulemaking action by FERC would be highly beneficial, and SEIA has proposed supplemental minimum daytime load screen for solar PV should be adopted.

Utilities should be required to collect minimum load data, or rely on well-established engineering techniques, to establish and estimate minimum load on circuits with significant PV penetration.

We also recommend that the utilities share this useful load data with developers by execution of NDAs, the non-disclosure agreements, because we've heard considerable amount of concern in terms of getting data out there. But if the developing world is willing to sign the non-disclosure agreements, that should alleviate the concerns associated with providing such data.

And posting such data in secured websites that developers can easily access upon execution of NDAs with utilities or regional reliability organizations. California ISO, for example, uses a similar approach, where market participants are allowed to go into their secured websites and download a tremendous amount of data, as opposed to having a public open forum. So we understand that concern.

Lastly, Sun Edison recommends that post-rulemaking, various working groups be formed among the distribution system stakeholders, to promote a more collaborative working environment, and implement transparent rules that provide a very clear and predictable path to interconnection for distributed generation.

We like the idea of having the working groups formed after the rulemaking as opposed to before, because that will slow down the rulemaking process. With that, I'd like to conclude my talking.

MS. KERR: Thank you. Dan Adamson.

MR. ADAMSON: Thanks, Leslie. I'm Dan Adamson of SEIA. I'm a Vice President of Regulatory Affairs and Counsel, and first just thanks to Leslie and everyone else on staff for all the work you've been doing on this issue. We know there's a lot of demands on your time, and so just by choosing to spend some time on this issue, we really appreciate that.

From what Bhaskar just said and the discussion this morning, it's obvious to everybody in this room that getting 100 percent of minimum load data, either actual data or an estimate, is really integral to making the SEIA proposal work, the Rule 21 proposal work.

You know, without that data or a reliable estimate, you cannot use the new screen. So it's very important. As far as the importance of the data, the Commission has a 20- or 30-year history, or at least 20 year history on the transmission side of using openness and transparency about what's going on on the transmission system, what type of capacity is and isn't available.

While this isn't exactly the same, it is the same in the respect that there needs to be transparency about this data. Developers need to have the same access to it that utilities have. You know, that's the way you're going to get open access. That's the way you're going to get transparency.

SEIA filed this petition in February, which is before the Rule 21 settlement was executed, and what we recommended at the time was that the obligation to collect and provide minimum load data be triggered when aggregate DG on a circuit line section is ten percent or more peak load.

So that would mean that in states like New Jersey and California and other areas where there are, there's a fair amount of penetration of solar and other DG on a circuit, that the utility or transmission provider would be required to provide that data.

But in other areas of the country where there's little or no DG, it wouldn't have any effect, and you wouldn't have to collect the data. So for example, in North Dakota, just to pick a state. It's unlikely a ten percent threshold would trigger a minimum load data collection.

I think for a lot of the coops, they were on earlier, I think, you know, a lot of them are in a position where the amount of DG on their system is slim to none, and so this wouldn't really have any impact.

We also raised the concept, which was later reflected in what Bhaskar said in Rule 21, that if you cannot get the data for whatever reason, that you would calculate it.

So now I'm going to talk about, I'm trying to follow the script here, you raised the issue of cost, because it does cost money to collect minimum load data, and some utilities have a lot of capacity already to collect this data. Many, and indeed I'm sure it's the majority, do not.

I think you've got to step back a little bit. There's a lot of utilities making investments in modernizing their distribution system, some under the ambit of Smart Grid, some under the ambit of, you know, just good practice. When they're doing that, oftentimes already they're including the capacity to monitor and report minimum load, and they should do that.

So if you're upgrading or modernizing your distribution system, you know, there's a lot of uses for this minimum load data, and you know, if we're going for a Smarter Grid, it would seem like a fundamental component of that would be not just knowing what the peak load is on a circuit, but knowing what the minimum load is.

So some of this can just be phased in over time, as other investments are made in the distribution system.

Just switching gears a little bit, you know, we're here today at FERC. So we're talking about FPA jurisdiction, not state jurisdiction, and even though I think this is an extraordinarily important proceeding, I'd be the first to tell you that, you know, FERC's jurisdiction over DG interconnection is narrow.

It occurs when there's a transaction involving an interconnection for wholesale transactions subject to an OAT. So that's a very definable universe.

So what that means is within its own jurisdiction, I'm going to assume, you know, that FERC will deal with the issue. But that even if you're using a line that's a dual use line, that's being used for both retail and wholesale interconnections, FERC has held previously, and I expect to continue to hold, that the cost allocation responsibility is with the state.

So although it is an important issue in this proceeding, it's important in terms of FERC's jurisdiction, if you go into dual use lines that are jurisdictional to states, this is going to be an issue of cost allocation dealt with by the states. My guess is that different states would deal with it in different ways.

In closing, SEIA is very eager, you know, we understand that this is a difficult issue. Some issues, I think, like the 100 percent of minimum load, at least in my humble opinion, black and white, you know, who pays for what is, you know, often depends on where you stand as where you sit.

So you know, we're eager to work with the

Commission, states, utilities and others, to come up with balance and effective solutions to the costs related to collection of minimum load data. Thank you very much.

MS. KERR: Thank you. Also just like we're having a little feedback, so if anyone has a cell phone close to a mic, please turn it off. Okay. Our next speak is Kristen Nicole. She is with the Electric Power Research Institute.

MS. NICOLE: Thank you, Leslie. Good afternoon and thank you for the opportunity to speak here today. As Leslie said, my name is Kristen Nicole. I'm the Senior Project Engineer in the Integration and Variable Generation Program at the Electric Power Research Institute or EPRI.

EPRI is an independent, non-profit mission-driven company performing research development and demonstration in the electricity sector for the benefit of the public. Our membership represents over 90 percent of the electricity base in the United States, and we're currently experiencing increasing growth in our international membership to the tune of about 15 percent.

It was interesting our colleague from enXco is here. We work closely with EDF as well as in France. For the past four years, EPRI's conducted a host of collaborative research efforts and facilitated dialogue amongst power system stakeholders, spanning all aspects of electricity generation delivery utilization, in fulfillment of this mission.

Myself, along with my colleagues Tom Key and Jeff Smith were co-workers on the Embril published paper referenced in the SEIA docket, updating interconnection screens for PV system integration. This effort was conducted in the context of many other cooperative research efforts we have going on at EPRI, related to renewables, storage, integration, interoperability, grid modernization, grid operations and planning, just to name a few.

As Mike Coddington introduced this morning, the white paper was intended as a stand-alone activity to provide a high level technical basis for discussion on this topic. So it's fascinating that it's led to such an intense conversation today.

As an organization, EPRI does not hold, take stands or hold political persuasions in policy-related activities. So we are, again, fulfillment of our non-profit mission.

So for our panel, we've been asked to address the issue of minimum load data as a potential measure for PV hosting capacity, in the context of the points Leslie distributed. The idea of the availability of certain types of data for this type of analysis, potential concerns associated with the use and sharing or transparency around the data, methods of minimum load estimation and alternate proposals to facilitate PV siting.

As mentioned in the paper, the 15 number, we talked about this this morning as well, so I'll try not to duplicate. But the 15 percent number originated from the half of 50, of 30 percent of peak load, which is generally rule of thumb for average annual minimum load.

The actual ratio of minimum to peak load varies widely based on many factors. These include, for example, the type of load being served on a particular circuit. It's important to remember that load is not the only factor. In fact, if there is one point that I could leave everyone with today, it would be that the interconnection process is unique, depending on the location in the utility jurisdiction.

The circuits, the system, the equipment on the system, the history of that utility, impedance. There's a host of different factors that will determine the outcome of how PV is going to perform in concert with the power system at that particular location. So the answer is that it depends.

The practice of managing PV penetration levels by simple benchmarking against load data works well in low penetration situations, as folks have identified today. Certain parts of the country, individual power systems are moving towards higher penetrations, particularly California, Hawaii, New Jersey.

For solar integration, it's important that codes and standards are continually reviewed and revised in accordance to maintain relevancy of the changing landscape, and folks echoed that this morning, with the activities going on in IEEE, as well as Rule 21.

The decisions made on this changing landscape are going to have implications for future generations. So in my opinion, it's important that policymakers strive to become as well-versed in some of these electrical engineering challenges faced by a variety of different parties associated with integration of DG.

These issues are complex and, in my personal opinion, won't be sorted out just today. So if the Commission decides to go forward with the working group or other stakeholder process in order to gather more information, it should be -- EPRI should be thought of, the staff and research that we conduct, as a resource for the community at large and the public at large.

It's known that PV has a strict daytime pattern based on diurnal cycles. So industry's interest in isolating daytime minimum load data as a factor is understandable and reasonable. I mean if you just look at the facts, PV's only on during the day. So it's a very unique characteristic of the generation.

The experience is that line section minimum load data is not widely available. Monitoring and grid modernization efforts, including Smart Grid, are increasingly producing a host of new data streams, and utilities are being bombarded with a lot of new data streams.

It's a matter of taking those new data streams and understanding how to effectively figure out which ones are necessary, how to use them. I feel like we're just at the beginning of this process for PV in general, and then also for some of the Smart Grid efforts that are underway.

At the line segment, it's rare that utilities will have minimum load data. Jose mentioned this earlier, unless the line segment happens to be a unique situation where it's representative of a full circuit. It's not uncommon for folks to have maximum or minimum load data through SCADA at the substation level or at the transformer level.

But if you have, you know, three to ten circuits coming out of that system, you don't necessarily have the clarity or the visibility below that. So that's a legitimate concern if the data doesn't exist, and then, you know, as folks mentioned, you have to understand cost allocation, understand how to monitor and collect that data.

So historically again, you haven't been able to get access to this data. This is really just the advent of digital recorders, including digital protective relays and others, the acquisition of system equipment that come on in the last few years.

I'm going to skip ahead here, just in the interest of time. But again, so line section monitoring again is not readily available. It's not impossible in order to collect this data, but it's extremely labor intensive; it's easier at lower voltages versus higher voltages.

So there are a lot of considerations in understanding where you're going to collect that information, and then also you may only be able to collect that information for downstream activities.

A positive aspect of availability of peak load data is that it's historically been collected as part of the system planning process. So you have, it's not just for one generation system. Utilities have institutionalized the need for peak load data. This doesn't currently exist for minimum load data.

So we're really, the impetus on collecting that data is solely based on this need. So if it was available, it's important to consider additional analysis that would be required in order to use minimum load data. Folks were mentioning earlier the potential of shifting load if you've got switching operations and load is shifting, or you have equipment that's down.

You might have a situation where, you know, you're able to collect minimum load data, but is that actually, you know, what's the uncertainty of that data? What's the activity below that data? So again, an analysis is also something to consider.

Online power flows have been mentioned as a solution to some of these problems for transmission system operations. This is feasible. For distribution operations, this is very new practice. So I'm sure, as folks will mention later, that type of future of being able to use that data is not readily available right now. This is a very new space for distribution system applications.

So in closing, EPRI is -- and I will just mention, we're working closely with the national labs, the CPUC, and the four major California utilities on a California solar initiative project, looking at alternative screening methodologies, with the goal of streamlining the interconnection process.

So this effort is underway, based on years of research. This is not happening overnight, but we did just get the project. So over the next several years, we'll be looking at trying to form a technical basis for the future of the screens, and again, this is based on the idea that every system is unique, every circuit's unique, so how can you take such a diversity of circuits or scenarios and figure out a way to generalize it, or at least condense it so that it is usable in broader scenarios.

We're using, you know, our existing experience in power quality monitoring. We have a deep distributed PV project that's going on, where we're collecting over -- we're collecting data from about 200 spots around the country.

We're using this data in our simulations and our open DSS models, to better understand and characterize some of the activities going on in the circuits, and we are working collaboratively with a lot of stakeholders in the room. So thank you for your time.

MS. KERR: Thank you. Next, we'll go to Roger Salas.

MR. SALAS: Thank you for the opportunity to participate in today's panel discussion. My name is Roger Salas, and I am a Supervising Engineer for Southern California Edison.

In my current role, I supervise a team of engineers who are responsible for reviewing generator interconnection requests, and for performance system studies under our FERC jurisdictional tariff, as well as under the

California Rule 21 tariff.

I respectfully encourage the Commission to reject SEIA's proposal that the transmission owners be required to collect and provide minimum load data to generator developers.

Our experience over the last three years with the review of approximately 590 applications under the SGIP, demonstrates that the current SGIP fast track process works as intended, by separating projects that could interconnect quickly without safety and reliability concerns, from those projects that require further study.

At SCE, the 15 percent screen is not the most significant factor as to whether a project meets the fast track requirements or not. Rather, the most significant factor is whether developers choose to propose projects in a transmission-constrained rural area, as opposed to proposing projects in a non-transmission constrained urban area.

Since January 1st, 2011, SCE has completed analysis of approximately 95 fast track projects. 31 of these projects were proposing transmission-constrained areas. Only one of the 31 projects qualified for fast track. The other 30 projects failed at least two of the other screens not related to 15 percent, related to the transmission constraints of the location where they're proposing to interconnect.

On the other hand, of the 64 projects that we're proposing in non-transmission constrained areas, 50 of the 64 projects passed the fast track requirements. This demonstrates that the existing fast track process is appropriately distinguishing between projects that no potential for safety and reliability issues, from those projects that require further study.

Furthermore, complying with SEIA's request will impose burdens, both in terms of resources and expenses, without delivering the benefits that the generator developers are expecting. In its request, SEIA proposes that utilities publish minimum and peak load data for all circuits with penetration greater than or equal to ten percent of the peak load.

However, the 15 percent screen does not apply the circuit level, but at the line section level. Looking at the SCE-distributed system, while we do have load data on approximately 5,000 line sections, we do not have load data on approximately 33,000 line sections.

For these line sections, SCE will be required to install new devices and communication systems to determine whether such line sections meets the ten percent load requirement. Furthermore, simply obtaining raw data is not enough. The load data will need to be analyzed before it could be provided to project developers, requiring additional engineering staff to verify and determine appropriate minimum loads for all line sections.

Proper verification requires trained engineers with knowledge of SCE systems and conditions. These measures are simply not practical and will not address SEIA's concerns. As explained previously, the most significant factor for the fast track analysis is whether the proposed project location is within a transmission-constrained area or not.

Approximately half of the line sections in SCE's service territory are in transmission-constrained areas. So publishing minimum load data for these sections will not enable more projects to pass the fast track.

In fact, even if these projects in these areas pass the 15 percent screen or even the 100 percent minimum load screen under supplemental review, these projects will ultimately still have to go through the study process, as these projects will fail other screens related to transmission problems.

Nor will SEIA's proposal provide any meaningful help to projects seeking to connect in non-transmission constrained areas because the existing fast track process works well for those projects.

Since January 1st, 2011, approximately 78 percent of fast track projects in non-transmission constrained areas have met the fast track requirement. They have proceeded under the fast track process. The 78 percent passing grade speaks for itself. The fast track process is working in the non-transmission constrained areas.

In conclusion, my experience with the fast track interconnection process has shown that it is working, and it is not unduly discriminating against solar developers. Of course, I'm interested in hearing other parties' perspectives in this issue, and look forward to further discussion today. Thank you.

MS. KERR: Thank you. Steve Steffel from Atlantic City Electric.

MR. STEFFEL: Thank you, Leslie. Steve Steffel representing PEPCO Holdings, and Atlantic City Electric is one of the --

COURT REPORTER: Would you turn your mic on?

MR. STEFFEL: Oh, sorry. Steve Steffel representing PEPCO Holdings, and I'm the department manager of Distributed Energy Resources Planning and Analytics. We have the three utilities, and Atlantic City Electric in southern New Jersey is the most active area. But we have solar going in the Delmarva Power and Light area, and also in this area of Washington, D.C.

Looking across the board on the feeder data that we do have, there are obviously some feeders that don't have this data. They have older data collection systems, metering and so on. Some of them are manually read, and of those feeders that do have this data, typically this data has not gone through scrubbing process.

So it would be, you know, starting there, that would be an extra effort to do all the error checking and make sure we've got correct data. We don't have typically of any feeders that have this load data by section. Perhaps there's some device out there that we've put in that may be recording it, but it's not something actively being retrieved by our SCADA system.

Things that would affect the accuracy and so on, phase imbalance, metering the inter-inaccuracy for estimation error would need to be accounted for if you're going to estimate the minimum load. And again, I had mentioned before, you need to take into account the minimum phase.

There are phase imbalances, 15 to 30 percent at times. They get balanced every so often, every few years. But you've got to really be careful not to overlook that. The installed PV will masking some of these loads, and there's changes due to weather, economics, the DERs being on and off, and all of that has to be taken into account.

So just publishing a raw piece of data is not going to be meaningful by itself. All these other things have to be taken into account. To make it even more useful, the pending systems, those with in service states after that load data was picked up, have to also be taken into account, which increases the complexity to make that data useful and meaningful, and something that can be actionable.

In addition, there's distributed automation and restoration schemes that are in existence on many feeders, and are being implemented throughout our system to improve the reliability of the system.

If the practice of providing the data is started, this type of data would have to be published in a public website, to ensure that there's no preferential treatment, and it would have to be updated fairly frequently to be of value. So there is a significant effort that would need to be made on the part of the utility.

Since there's a lot of other screens and a lot of other things that can limit or trigger a study, and it would not ensure that the developer could put a system in of a particular size at a certain location on the feeder, we feel like, you know, it's a lot of effort that may not provide as much value as was intended.

The other thing is it was brought up in New Jersey, and when the desire for this data was brought up, one of the major issues was cost. Who would pay for it? We never had the solar industry sign on to paying for it completely. So it would obviously be the rest of the customers that would be paying for it, if we actually do move ahead and do it.

I mean there's measurement equipment, there's personnel time for all the analytics, and then the posting of the data and maintaining of that data. So I think those things are significant to consider and weigh against the value of that data being provided. Thank you.

MS. KERR: Thank you. Tim Roughan from National Grid, representing EEI.

MR. ROUGHAN: Thank you again for giving me the opportunity to speak like this morning. So going through this particular question, I think ultimately, you know, Dan is correct, that there's lots of activity, lots of planning for reliability enhancements, distributed automation, to increase reliability of the system, while maintaining low delivery costs.

I mean it's, I mean folks who have been in the regulatory process know it's quite a process to get a rate increase put through your state regulator. So when we have these long-term plans, and if they've been approved, they need to go down the same path. There's a lot of reporting requirements to show that you're making progress on putting in this equipment.

If and during, in the middle of that process you now have to adjust or modify where you're putting your equipment because a circuit gets to ten percent saturation for PV, that will simply result in some inefficiencies of that deployment.

We need to make sure we work with what the regulated utilities are, the distribution levels are already doing, and not impose additional requirements on them, that require us to go back to each state regulator to get additional funding to do other work that we hadn't already talked about.

I talked this morning about the three, five, ten year capital plans most utilities go through and propose to the regulator. Within those capital plans are things like DA, are things like Smart Grid enhancements, are things like communication and controls and intelligence on the system, so we can automatically switch devices around.

So those have been set up and are in place and we'll work on those plans going forward. Again, interrupting that plan obviously won't be the most efficient way to move forward, because ultimately getting the minimum load data is going to be a long term process. It won't happen overnight.

I know for most utilities have significant data at the substation level, at the newer substations. We all have plenty of substations that have been out there for many years, that likely don't have the sophisticated metering required. Many of the older substations only have peak load measurements.

They don't even have the ability to collect minimum load without replacing all the metering equipment, which is typically done in an upgrade when that substation then comes up due for an upgrade, if you will. So again, slowly deploying this type of equipment is really the way to get this minimum data.

We had an extensive conversation this morning about the true value of that minimum load data. I mean I'm still of the opinion that that's just a piece of the pie to look at, and to use it as a be-all to end-all screen will limit the flexibility of the distribution utilities, in terms of working with their systems, working to meet the local customer needs, and the reliability needs.

New customers come in, new customers go out. You know, a customer who had a three shift operation two years ago goes to two shifts. Now they don't have any load on that Saturday and Sunday afternoon, where typically your minimum daytime loads are during the late May or early October periods up in the Northeast for example, and that can just change.

We won't know that that entity went from three shifts to two shifts. Until they volunteer and call us, we simply won't know. So there's a lot of moving targets here, and putting together, putting out a rulemaking and then putting working groups together to try to figure the rule out, I think, is going the wrong way.

So we want to point to set up the working groups up front to work out all the details. So when a rulemaking is actually established, you've got that breadth of experience and knowledge to work off of, versus pushing forward a rule that frankly will undermine significantly some utilities' ability to look further into the issues about the DG looking to be interconnected at that site.

We talked a lot about the locational aspects of these projects. I said it this morning. These projects are being built on the fringes of the territory. They're being built in the rural areas. They're being built on the weaker parts of the system.

So whatever the loads are out there is kind of immaterial, if the conductor site is already a problem, or if the voltage regulation issue is already a problem.

So I think we're kind of getting ahead of ourselves, trying to figure out how to get the minimum load, because we really haven't sorted out the answer. Is that really what we want to get? What's the problem we're trying to solve?

Just because customers don't pass the fast track doesn't mean they don't, they aren't or cannot be interconnected. There is a study or potentially upgrades. But projects, we in the current phase of these multiple megawatt projects, which have only been a couple of years for us, we haven't seen any drop out.

Even with a study, they're going forward. They're getting built. They're producing solar power. So we have yet to see a project that fails a fast track not go forward and still be built. Now perhaps it's happening in other parts of the country. We're still only in the first two years of it up in the northeastern states.

But realistically, I think we have to recognize what problem are we trying to solve here. I think we first need to have that discussion amongst the technical parties and the different groups of utilities, and of the industry, to come up with that set of problems we're trying to solve, and then come with solutions, and then a rulemaking would be the appropriate method. Thank you.

MS. KERR: Thank you. And now to Kevin Fox of Keyes, Fox and Wiedman, representing IREC.

MR. FOX: Thank you, Leslie. Thank you. My colleague, Mike Sheehan, appeared on the first panel and provided a little bit of background information on IREC. As Mike mentioned, we are a 501(c)(3) non-profit, non-lobbying organization that is presently active, working on interconnection reform efforts in about a half dozen states including California, Hawaii, Washington, Massachusetts, New Jersey and also, of course, are active here at FERC.

In the half dozen states where IREC is presently active, we see three developments driving interconnection reform efforts, all of which were touched on briefly this morning by panelists.

First, utilities are seeing a significant increase in interconnection requests in many parts of the country. Second, higher penetrations of distributed energy resources are being interconnected to our country's distribution systems. Third, new programs like feed-in tariffs and community renewables are bringing larger generators online that do not primarily serve on-site load.

These are new conditions that have emerged primarily in the last three years, well past the time that FERC adopted the small generator interconnection procedures. Much of the increase in interconnection activity we are seeing is due to a rapid increase in solar PV deployment.

According to the Solar Electric Power Association, in 2011, utilities interconnected over 62,500 PV systems. To put this in perspective, about 350 non-solar PV plants larger than one megawatt were expected across the United States in 2011.

That means that for every non-solar PV plant larger than one megawatt, utilities processed 175 solar PV applications. Conservative forecasts indicate that this number will grow to over 150,000 interconnections by 2015.

SGIP was not designed to handle this volume of interconnection requests, nor was it designed to address higher penetration levels that we are now seeing. Nor was it intended to facilitate larger and more complex generators that are increasingly being interconnected to our nation's distribution systems.

The impact of these market changes has been most significant in states like California, Hawaii, New Jersey and Massachusetts. However, these states are merely precursors. According to the Solar Electric Power Association, 22 utilities interconnected more than 500 PV systems to their electric power systems in 2011.

In fact, utilities with the highest cumulative solar watts per customer installed, now include utilities in Georgia and Tennessee. For these reasons, IREC believes the time is now right for FERC to update SGIP, to it continues to facilitate solar market expansion.

California and Hawaii have both made attempts to keep the number of applications manageable, by providing more information to developers in advance of a formal application being filed. In both states, it has become apparent that developers are filing multiple applications to identify low cost places to interconnect.

In particular, developers may file several applications for the same projects, or portions of projects on nearby parcels, looking for how much capacity can be developed before expensive upgrades are needed. Hawaii and California are pursuing approaches to reduce the number of speculative applications.

One approach is to provide more information about low cost places to interconnect up front before a formal application is filed. Providing this information has the additional benefit of making better use of existing distribution system infrastructure, without requiring significant upgrades.

In California, stakeholders have proposed a pre-application report, to provide specific information on proposed points of interconnection. Rachel Peterson from the California PUC discussed this briefly this morning.

Against this backdrop, IREC would like to make three recommendations in response to the specific questions posed by FERC staff.

First, IREC believes the pre-application report should be incorporated into SGIP. Section 1.2 of SGIP currently allows for the provision of relevant information. But this section does not provide time frames for providing information, or a specific list of information that must be provided.

It also does not provide reasonable compensation to a utility for time spent providing this information. IREC believes SGIP Section 1.2 should be modified to include greater specificity. Specifically, we endorse the pre-application report content of the proposed California Rule 21 reforms.

We believe that this is the best means to provide developers with information to facilitate site selection and streamline the interconnection process.

Second, to the extent minimum load is a relevant consideration in the interconnection process, and IREC believes strongly that minimum load is a relevant criterion, this information should be provided in the pre-application report, so long as such information is readily available.

We do not believe the pre-application report should require utilities to make calculations or estimations, but rather should be a means of sharing information that is readily available.

Third, we believe FERC should not mandate a specific means of collecting or estimating minimum load data. We believe that there are a variety of approaches that utilities can use to calculate or estimate minimum load at the line section. We appreciate the fact that this data may not be readily available, and that the current infrastructure may not be installed, so that utilities have it ready. But we do believe that utilities have the means to calculate or estimate minimum load.

This includes making use of Smart Meter data and SCADA systems deployed at substation distribution feeders. It also includes use of power flow modeling and the use of standard load profiles for different customer classes. Different utilities have different tools at their disposal currently, and we believe they will be developing additional tools over time.

We believe utilities should have the flexibility to use the tools that they believe are most cost effective for their situations.

Finally, we believe that requiring the use of minimum load data in the interconnection process will give utilities a reason to collect this data. Once it is collected, it can be made available in the pre-application report, and applied more readily in the supplemental review screening.

IREC believes any concerns associated with providing such data to generation developers through a pre-application report can be easily addressed through simple non-disclosure requirements. Thank you.

MS. KERR: Thank you. So we have some staff questions, and no Commissioners with us at this point. So we'll get started. Each of you, I think, touched on this a little bit, but I want to ask it again, and try to drill down a little bit, the extent to which actual line section minimum load is currently available, if you have a feel for that either for your utility or for regions of the country.

If it's not currently available, will it be available in the near future, and if you can give us some estimate of what time frame you think that is? If it's not currently available, what are the obstacles to collecting and providing that data? Again, like this morning, if you could just indicate with your name plate that you're interested in answering. Okay. Mr. Salas?

MR. SALAS: Yes. As I said in the opening statement, the numbers that I provided are pretty much out of our databases, where I stated that 33,000. So altogether, we have approximately 38,000 line sections more or less. 33,000 line sections do not have any data whatsoever.

MS. KERR: Does that just include minimum load data?

MR. SALAS: No. No load data whatsoever.

MS. KERR: So you couldn't get peak load data on those either?

MR. SALAS: We would have to go under some estimation if we needed to, on a line by line section when necessary.

MS. KERR: So if you had an interconnection request under the 15 percent screen, you would still have to estimate that data on those line sections?

MR. SALAS: Absolutely. In a line by line section, you have to do it and some are using different methods, different tools.

MS. KERR: Would those same tools for estimating peak load, could they be used to estimate minimum load?

MR. SALAS: Could be. But again, it would make it more complicated. But again, doing it on a line by line section during like a supplemental review process, where you have, the engineers have more time to determine what type of customers we have in the line section, you know.

We can look at some meters. We can, you know, look at some trends, whatever. Yeah, we could do it, but again on a project by project basis, line by line section, you could do it, but definitely not on 33,000 sections.

MS. KERR: Could you do -- you talked about doing that as part of a supplemental review process. Are you talking about a general supplemental review process like in the current pro form SGIP, or in the supplemental review process similar to the California Rule 21 process?

MR. SALAS: In California, we do both. In other words, you know, what we proposed under the Rule 21, California Rule 21, it's the same screens that we utilize under our FERC jurisdictional tariff. In other words, the tariff allows us, it's general enough where it says if any of the ten screens fail, you can proceed to a supplemental review.

It doesn't really say the exact steps and so on and so forth, but we as engineers, we know what those steps are, and we implement those steps both under the FERC jurisdictional tariff, which are the same as what we would apply under the Rule 21 tariff.

MS. KERR: Okay. Just to clarify, so the proposed Rule 21 settlement, those are the steps you're talking about in the supplemental review screens? Okay. That's what you would use currently to do a supplemental review? Okay, thank you.

MR. SALAS: And again, that's the reason why we have the percentage, 78 percent of projects that pass fast track under the, in the non-transmission constrained areas.

I would say about 75 percent of those failed the initial 15 percent, but went into the supplemental review, in which we looked at the three additional, voltage regulation, safety and the three additional screens under this, that we would outline under Rule 21. That's how the percentages, it's much higher.

MS. KERR: Okay.

MR. SALAS: But to answer the original question, you know, 33,000 line sections we don't have line data for. We will have to install very large amount of equipment to be, and communication systems, to be able to collect the data.

Even once you had the data, again as I stated in my opening statement, you still have engineering staff that needs to look at that data, to analyze each line section. It's just an incredible amount of work, for really I don't believe that is really necessary for what's intended right now.

MS. KERR: Just one more question. If you did have to estimate either peak or minimum load, because it sounds like it's a similar process, about how much time does that add to the interconnection process?

MR. SALAS: Well, I think the time that we allotted in the Rule 21 reform already accounts for that.

MS. KERR: Okay.

MR. SALAS: So you know, I believe it's 15 business days or something like that that we have the supplemental review, that we allow as the time to do that.

MS. KERR: Okay, okay. Okay, Ms. Nicole.

MS. NICOLE: So just to echo again, from my understanding, and this is just ballpark, because you're going to have, again, every system's different, every, you know, section's different. You have different equipment that's, you know, some of it's newer. I mean folks have referenced Smart Grid and AMI. We all know that that's not a reality for every meter in the country.

So you have to bucket out different parts of the system, and just in your mind bucket out you're going to have different data availability for different types of situations. So just to kind of ballpark, from my understanding, you can get -- within SCADA systems, you can get min-max.

But you're going to get that more utilities have those type of data acquisition systems at the substation or transformer level, so it's upstream. So you have this kind of gap in knowledge, where folks will have, you know, you will understand minimum load, you know, over a year or so at the substation level for folks who have those systems, which is not everybody.

I would say, and folks can correct me if you think I'm wrong, but you know, around 50 percent or so. It's not every situation and everybody's different. However, once you have those types of measurement points, then you have to get into the specifics.

If you have certain types of equipment out there, for example if you have digital protective relays, those would be able to give you some sort of --they would ping back some sort of, communicate some sort of information back to a data acquisition system, for example. But it would only be through a specific period. It would be like in an event or something. Then it would ping back that information.

So a lot of the, or cappings (ph), for example, and the newer ones could communicate back that type of information. Not every, you know, line section or line's going to have those types of equipment on there. So you just have to work with whatever's out there, whatever is in the planning to be built.

That being said, you know, over the next few years, as Tim was mentioning, folks have three, five, ten year plans for build-out, and so it's something that we should be thinking about in the future. You don't have that institutional planning capability for minimum load data versus peak load data. So it's just not something that folks have done historically.

MS. KERR: So on these build-outs, absent a regulatory requirement, is minimum load something that, you know, if you're upgrading your system or doing a Smart Grid program, is that something you would be looking for, looking to install equipment?

MS. NICOLE: I mean from my understanding, that's not -- what would be the purpose for needing it? You would need it in case a PV developer wants it. You wouldn't necessarily need it for a planning purpose, because you're planning for capacity.

So you're, so folks aren't necessarily building down your system requirements.

MS. KERR: Okay, thank you. Mr. Steffel.

MR. STEFFEL: We have a number of feeders that they would maybe constitute the line section, in which case some of them have and some of them don't have, just like others have mentioned, that there's historical data.

There would probably be two sources of getting this demand-type data that you can roll up to line sections. One would be SCADA equipment that you actually put out on the feeder. Number two is if you have AMI and you can roll it up into feeder sections.

We have had AMI efforts in, I guess, two-thirds of our utility, and in the one area where we have the most solar, the Public Service Commission has not wanted to have AMI in that area. So in that area, it's kind of difficult to put that together by line section.

As Kristen mentioned, we don't have as much of a purpose to focus on minimum or peak. We're focused on meeting the peak load, and making sure that we've got proper voltage and we're meeting the, not overloading equipment and so on.

I think that in time, this type of data will be available. But I think it's kind of premature to try to request utilities to provide it. The problem is that in the discussions we had in New Jersey, where you know, this data was desired, the solar developers and so on really didn't want to pony up to the cost of collecting it and putting out the measurement data.

So somebody has to pay for this effort, and it's not an insignificant effort. As I said, putting out unscrubbed data and not taking into account all the other factors, doesn't make the data very useful.

So to get good data out there that can be actionable, there is a significant cost, and we've got to either bite the bullet and somebody has to pay for it, or you know, we have to say well, it's not worth the value at this point.

MS. KERR: Is there -- Mr. Fox mentioned the California reports that developers pay $300 to receive. Is that some sort of mechanism that would work to pay for the data?

MR. STEFFEL: Not when it costs, you know, tens of thousands of dollars to pick up the data, on a circuit or a section.

MS. KERR: Okay. Mr. Roughan.

MR. ROUGHAN: Yeah. I mean there is no reason for us to collect minimum load data at all today. It's not what we design our system around.

We design our system around providing reliable service to our customers, and be able to do that under circumstances where you've got outages, feeders, storms, you know, care accidents, squirrel incidences, etcetera. So that's -- it's all driven around that.

I did want to just clarify my comment about utilities have long term, three, five year plans, ten-year plans. That's only once the regulator has agreed that the cost versus the benefits of that deployment are right for that state.

Right now, we're still going through significant pilot efforts on Smart Grid. All the DOE funds that went out there, a lot of pilots. Everyone's waiting to show that the cost to make the system smart and advanced metering and the customer interaction is less than the benefits you'll derive.

That hasn't been proven out in all cases, where the regulators of the states realize that if they agree to a multi-tens of hundreds of millions of dollar effort, because this is a significant amount of work we'd be doing over time, they need to be comfortable that the benefits of that price tag are worth spending that money, because we're talking about a revolutionary change in what we're doing to the utility distribution and transmission systems.

And again, they need to be very, very comfortable before they give us the green light to put in that five year plan or whatever it is, that the costs we've estimated are lower than the overall benefits. And until that's in place, there isn't a plan that's going to provide minimum load data for most of those line sections which we've been talking about.

MS. KERR: Okay, thank you. Thanh, do you have a question?

MR. LUONG: Yes. I just had a clarify question. You know, so far I heard that there's a lot of area that now have no peak load data or even minimum load data. What happen if a PV would like to connect to that area, not even a fast track, and then you had to perform a system impact study? What data do you use to perform the system impact study?

MR. SALAS: Is that question to me?

MR. LUONG: For anyone, you know, engineer, that you can provide a system impact study? I heard a lot that you had no information. So how do you perform the system impact study with no data?

MR. SALAS: Well, during the system impact study phase, we do have the time to look at, you know, again the information, the type of customers that we have, the load profiles and so on.

So we're not saying that we don't have any data. We're saying that it's not available to just publish and click a button and say here's the minimum loads. So we know the customers; we know who are, which customers are on our circuits, what their load profile is, and we know the peaks, and we can probably do a good estimation on the minimums. That's what we use for study purposes.

But again, we do that on a project by project basis, when we have the time and the resources and the funding to be able to do such research.

MR. DAUTEL: I guess I have a little tweak on your last question, which is not why are they putting in minimum, or is it worth it to put in the minimum load collections?

But I assume there are times when They're putting in meters to do the peak load collections, and I would be a little surprised if the incremental cost to add minimum load connection to equipment that can already do peak load collection is significant.

I don't know if that's a question or a comment. Does anyone have any reaction?

MR. ROUGHAN: Well, I think you're right. Once you upgrade that substation, you put in the full metering suite of what you normally put in for a new substation.

You're right. You've got data. You've got plenty of information. Minimum, maximum, you've got all the data, when that substation is being upgraded.

That's at that substation. That's at that high level which Kristen is talking about. But there's still relatively few times when you're putting that peak load data at a line section, at a feeder that's out, equipment out on the circuit.

So yes. When we're upgrading the sub, you get it all. It's just when we're talking about the line section piece here, that's the challenging piece.

MR. DAUTEL: Right. I guess I'm primarily interested in how this applies to the line section. So you're saying they don't, they often don't have that equipment and there's no plans to put it in. But then I'm left assuming that they're doing mostly estimations today then. Would that change significantly if they started estimating minimum load data, I wonder?

MS. NICOLE: So yeah. I would say, I mean the 15 percent idea came out of an estimation. 30 percent is an estimation. Whenever, I forget who mentioned it this morning, I think it was Mike Sheehan, talking about the SMUD example, where you're trying to close the gap between estimations and measurements.

So anytime you can reduce that uncertainty in your estimations by improving your measurements, and like I said, there's a couple of different types of ways to validate those estimations with different measurements.

So you could do SCADA. If folks had a new substation with SCADA capability, you could potentially flip a switch or maybe it comes out of the box with all types of data. So it wouldn't necessarily be a huge burden in that instance. However, you're not going to find every utility with that type of system.

So you're going to have different scenarios within a utility, or you might have different utilities. My personal thought on this would be that it might disproportionately impact folks who, you know, are IRUs, versus a coop, versus a muni, the extent to which they are investing in sort of, you know, SCADA activities.

Then along the line section, you would have literally sort of a monitoring device that you'd have to install. So you would purchase the equipment, which would be essentially a few thousand dollars, depending on what voltage level you're at, and then you'd have to install it and maintain it.

And then to Steve's point again, it would be once you have that data in place, pulling it back, because again it's only a time stamp, right? So making sure that any data that you have is put into context of other things happening out either, you know, below the transformer level or amongst different feeders.

So it's not that it's impossible; it's just again, it's a matter of how much time and how much cost potentially in the different types of ways that you could collect data, and then get a precision on exactly what data you're looking for, and then what's the value of that data at the end of the day.

What we're doing within EPRI with our CPUC project is trying to get away from this idea that you're really just looking at load data. You're looking at, you know, the type of circuit, how can you characterize different types of activities on the circuit, because you're going to have, you know, many different types of circuits out there.

So is there a way to take some of these unique characteristics and develop methodologies to understand certain types of behaviors, and then validate those to understand PV hosting capacity. So the idea would be to, instead of having one number, like a 15 percent number, it would be more of a customized percentage, or not percentage, but a customized penetration level.

So you know, one particular area might be three percent, one might be 50 percent. So that's kind of the direction that we're going in, is away from a one-size-fits-all approach, with penetration and with maybe one data point, but moving more towards sort of an understanding that since you have so much diversity, how can you customize it or create some sort of methodology or platform that would again streamline the interconnection process. It just makes it easier, and frankly more accurate potentially, if we're successful.

MS. KERR: Is the idea to make a hosting capacity idea transparent? It sounds very individualized, so it might be difficult to describe?

MS. NICOLE: No. I mean we're -- no, it's extremely transparent. I mean the research that we're conducting, it's repeatable. I mean we're working with National Labs and with CPUC. So it's going to be, it's public research.

You know, the lack of transparency, in my opinion, is because it's complex. It's not because there's not information out there or forums where people are having a lot of conversations about how to best address these issues.

It's just that it really is a challenging problem, and you know, you talk on what's happening with PVs specifically, and you look at demand response and electric vehicles, and you try to take all of these challenges in context, and it's really not an easy challenge for engineers.

MS. KERR: Okay. Michelle.

MS. DAVIS: This is just a follow-up question for Mr. Ray and Mr. Fox. You both mentioned the execution of non-disclosure agreements to keep minimum load data secure, and I was hoping you could expand upon the precise concerns associated with making that kind of data and presumably peak data available to generators, generation developers.

MR. RAY: I think in the past, what traditionally the developing world has heard, is that there is considerable concerns about putting such data out there in the public domain, where there are some security concerns.

So the revival to that argument has been that if certain developers who have projects in the utility queue, that has legitimate business reason to get that data, would utilities be willing to share some information under a non-disclosure agreement, where they don't feel that they have to put the data in a completely open public forum?

Only a handful of participants or stakeholders that really have a legitimate business reason to get such a data, should be able to get access to the data under NDA. Does that take that security concern from the table?

MS. KERR: Did anyone else -- I can't remember who else you wanted to ask that question of.

MS. DAVIS: Mr. Fox mentioned it.

MS. KERR: Okay. Mr. Fox.

MR. FOX: Sure, I agree with that answer. I think what IREC is proposing here is to provide information, not through a publicly-disclosed website that would make information about utility infrastructure generally available. California and Hawaii both do that currently.

That could certainly be helpful, and I think that those states have pursued that approach, because it helps facilitate achievement of their policy goals. They want DG to go into particular higher value locations, and providing a map that demonstrates or shows where those higher value locations are is helpful to achieving that goal.

What we're talking about here is providing information through a pre-application report, where information on a specific point of interconnection would be provided to a developer requesting that information, so there isn't that sort of public disclosure issue.

MS. KERR: And you've held your name tag up for a while. Did you have something else you were going to answer as well?

MR. FOX: I do. Thank you, Leslie. I think it's important to bring the discussion about metering and the gathering of information generally sort of back to the policy issue at hand here. You know, we appreciate that not all utilities have minimum load data on the majority of their circuits.

So therefore providing that information today in a pre-application report would be challenging. As I mentioned, we think it's important that the pre-application report only require utilities to provide the information they have at hand.

However, I think it's important to stress that that does not mean that minimum load criteria cannot be incorporated into a supplemental review process. The reason is we want to avoid a chicken and egg problem, where the answer doesn't become "we don't have it, so we can't use it. But it's not needed, so we don't collect it."

Because that status quo gets us nowhere, and we'll never have this information. Roger talked about the supplemental review process in California, and how that works, and the fact that it gives utilities an additional 20 business days, I believe it is, and $2,500, so that they're compensated for the calculation or estimation of what the minimum load is.

You know, that is the approach that we would certainly endorse. Then as that happens, more data will be made available. I think, you know, there's an important point that shouldn't be overlooked here. Kristen, Steve, Tim, I think, all made the point that there's no reason to focus on minimum load data today.

As I mentioned earlier, incorporating minimum load criteria into the supplemental review process will give utilities a reason to collect this data, and as they collect it, they'll then be able to make it available through the pre-application report.

MS. KERR: All right, thank you. Mr. Steffel.

MR. STEFFEL: Just a quick comment. You had mentioned a little question on the hosting capacity, and we want to acknowledge EPRI's doing an excellent job on that. There's a few pages at the end of the handouts we gave that are the results of their hosting capacity on the rural feeder. So if you're interested, that has a little bit of their methodology in it.

MS. KERR: Okay, thank you. Mr. Salas.

MR. SALAS: Yeah. I wanted to comment back on Thanh's original question, I guess, as far as, you know, I guess his question was related to once you do a project, you know, what does it take to put additional equipment out there, to obtain the minimum load data?

One thing that we have to keep in mind is that we are under a lot of pressure to ensure that we serve our customers, at a minimum amount, you know, of the cost, minimum of cost. So when we have overloaded systems, we try to do the minimum that we can, to be able to continue to serve our load reliably and safely, and maintain the systems without becoming overloaded.

Putting additional equipment out there, and typically that basically what it means is if we have a circuit that's overloaded, we put a new breaker at the station, typically put a wire down to a specific area of a circuit, break up a circuit in half or something like that and call it good, right?

Putting additional equipment out there, that would require putting communication systems, putting more monitoring equipment. So even on those projects that are currently in the pipeline, now you're talking about increasing the cost of those projects.

Once you increase the cost of those projects, now you have to take the money away from other projects that are required to continue to serve the load.

So it's, you know, even on existing projects that are under the pipeline, just because they're new projects doesn't mean that you can put the equipment for monitoring the minimum loads out there, because that's going to be an incremental cost for which we don't have the money for to do.

MS. KERR: Okay, thank you. Mr. Adamson.

MR. ADAMSON: Yeah. I just want to make a quick comment on something Kristen said. She mentioned putting together kind of a customized load penetration thing, and that sounds very appealing, something we would support.

But our near-term focus for this petition is 100 percent of minimum daytime load screen, which the lab, you know, EPRI report lists in terms of short-term solutions, and there's a lot of, you know, more can be done. But we're trying to walk before we run here.

MS. KERR: Okay, thank you. Mr. Ray.

MR. RAY: Okay. So just one comment in terms of what we've all heard earlier, in terms of the fact that collecting load data is very expensive, it's time-consuming, it takes a lot of resources.

I guess given that there is a strong signal from the solar developing community that's going out, in terms of the genuine need for getting the minimum load, have we vetted enough or had a stakeholder initiative, especially in the high penetration areas, in terms of understanding what is the cost of such load data collection, and how much does load monitoring devices would cost.

Perhaps a middle ground or compromise would be to take a tiered approach, and install the load monitoring devices in the areas where traditionally interconnection requests are much higher than other areas.

Because utilities typically have a pretty good understanding of where our higher concentration of interconnection requests that are coming in, as opposed to other areas, where developers are not that interested in building projects.

So could there be a tiered approach that could be adopted, in terms of leveling out the cost of such installations and getting the minimum load data to the solar community. So I think it's worth exploring into that world a little bit more, as opposed to being having a dismissive approach of saying that it costs too much money and there's just no need for such minimum load data. I think it requires more discussion.

MR. DAUTEL: And in fact, isn't the proposal to only require these on line sections with at least ten percent of minimum load, or I'm sorry, of peak load?

MR. ADAMSON: Yeah, that's the SEIA proposal, is that the obligation to collect minimum load data would kick in if a circuit line section, you know, hit ten percent of peak.

MR. DAUTEL: And do we have a sense for like, I know Roger you said that there's 38,000 line segments in SoCalEdison. Do you have any sense for how many of those would be impacted by a proposal like that? Or of the 5,000 that are already monitored?

MR. SALAS: Yeah. I'll answer that coming from Bhaskar. Yeah, frankly I mean you're talking about 38,000 line sections that we have.

I would say, gosh a rough guess, probably about 95 percent of projects probably don't have, and that's just a rough number, don't have the ten percent that they're looking for, but yet they're requiring us to, or also be required to provide that data, even though it's not necessary.

Because with how many applications we have at SCE, probably 1,000, you know, or something like that, you know, maybe 1,100. But we have 33,000 line sections. So you know, it's just a very enormous amount of line sections for which data doesn't exist, and a lot of work needs to be done.

The other thing that I want to point out, according to Bhaskar, is that concentrating or getting the load data for these areas with higher amount of requests. Well, that's taking into account a FERC tariff and CPUC tariff.

We have about, I would say, about 75 percent of projects are in what we refer to as transmission-constrained area, where basically out in the desert, there's no load out there, and any amount of power you put into the distribution system is going to flow back to the transmission system, and creates problems with other projects already proposing to connect to the transmission system.

So putting that information in that area really, it's not going to help, you know. So you know, if the proposal was to say well, just look at the areas of higher concentration, well that's the areas, that's the desert, okay.

So really even if you had the data it doesn't help you, because you have to go through the study process, because you have to be combined with the rest of the projects that are connecting to the 66 kV system, the 115 kV system, and those that are under CAL ISO control.

So you have to put them all together to be able to study them together. So really you don't, that's really the worst location you want to put them in.

MS. KERR: So are those locations, I don't think we've talked about it yet in this panel, but earlier today we talked about the maps that the California utilities have to put out, in addition to the reports, in the Rule 21 settlement. Would that kind of location show up on the maps?

MR. SALAS: Absolutely. We definitely on the maps we have, there are various levels, and we basically said oh, this area here, it's a transmission-constrained area. Do not, well you know, be aware when you propose projects in this area, because they're going to have to go through a study process.

We provide information as to where our load centers, where is there's no transmission problems, and we have, you know, maps that show whether you can, you know, those circuits that have high amount of -- high loads and low generation.

So that if you see a green circuit, that means that this project can potentially pass the fast track. But a minimum, if you were to use the maps to say don't, stay away from the transmission-constrained areas. So be aware that there's a transmission problem here. If you stay away from those, your minimum can go through the ISG study process, and still interconnect with them.

MS. KERR: So in putting together those maps, even that even the peak load data, it sounds like not always available by line section, are you using substation data or --

MR. SALAS: Transmission system data.

MS. KERR: Transmission system data?

MR. SALAS: Yeah. I mean basically it's all the generation that's being proposed in the distribution, subtransmission and transmission system, and then determining that there's already, you know, 115 or 220 kV problems out there, where lines need to be upgraded.

So knowing how long it takes to do those type of projects, really putting additional projects on the distribution system is problematic. So we don't -- on that level, we don't even use the distribution level. We use the transmission level.

MS. KERR: Okay. Okay, thank you.

MR. LUONG: I'd just like to clarify one more thing. So you mean that it's a transmission constraint on a transmission system, not on a distribution level?

MR. SALAS: It's both, but you know, typically, distribution issues can be resolved quickly. So if you're putting projects in a distribution, where there's no transmission problems, you'll be able to find the problems, you'll be able to mitigate them. You can go through the independent study process and still interconnect, you know, quickly.

But in those areas that have transmission problems, it's just -- you really have to be studied together with all the other projects. It wouldn't be fair, you know, to put 30 megawatts of 1.5 or 2 megawatt generator projects, and allow them to interconnect, while you have the other transmission projects being held back. So you know, that's really where the problem is.

MS. KERR: Okay, Mr. Ray.

MR. RAY: Yes. Just a quick comment on that whole question about the transmission, you know, becoming a global issue. It is true, we all understand the fact that, you know, when you've got a transmission level constraint, that that impacts every little generator that's going into that cluster.

But the reality of the fact is, I'll just use Edison as an example, is there are several transmission projects committed, because there are other large-scale solar projects going into the transmission level that has triggered those congestion, and they're being addressed by building transmission to open up those bottlenecks.

The reality of the fact is because FERC's plan approval is in place, and several transmission projects have been undertaken, I think we need to decouple those issues and take a look at the distribution system at some point, because those transmission bottlenecks are being addressed and they are going to be resolved, because several projects are already under construction.

So I think that may be the case very well today. But in the near future, those transmission bottlenecks, when they go away, we're still stuck with this whole distribution level, 15 percent minimum load screen issues, because the transmission projects are going in, and billions of dollars are being invested under FERC plan approval, to take care of those issues, because they are more pressing.

MS. KERR: Mr. Salas, do you have a reply?

MR. SALAS: Yeah, definitely. Yeah definitely. We're not saying that those projects cannot interconnect, okay. We're saying that those projects are going to fail, specifically fast tracks screens number nine and ten.

So they are not -- we're not talking about whether or not those projects interconnect. We're talking about those projects have to go through further studies, because they're failing -- they're not failing the 15 percent screen. At that point, it becomes almost irrelevant, you know.

It's a factor in the distribution, but you're going to fail nine and ten, and no matter what, you have to go through a study process.

MS. KERR: Okay. We just have a few minutes left, and I have at least one more question. But Mr. Adamson, did you have a comment?

MR. ADAMSON: Yes. I mean it's quite clear that, you know, minimum load data is just not available from a lot of utilities, and that's going to change over time.

We don't know how quickly. But I think what the issue is here is Order 2006 was essentially the 15 percent threshold, a way of estimating minimum load, and it's one that's turned out to be overly-conservative and turned out to be a market barrier to solar in the current environment.

What we're asking you to do with SEIA is to adopt a new and improved way of estimating minimum load, either providing for minimum load data or estimating. It's very clear from the panel that there's going to be a lot of estimating. It's something utilities have done, even for peak load where they don't have it.

So you know, I hope that everybody goes ahead and gets minimum load data available right away. Realistically, it's going to evolve. But what everybody can do today is they can do a much better job of estimating minimum load on a circuit than they did under the 15 percent rule.

MS. KERR: That leads me to my next question, which is what are the current concerns associated with estimating minimum load, to the extent we haven't talked about them already, and what can we do or what can utilities do to alleviate those concerns? Mr. Roughan.

MR. ROUGHAN: Yeah. There's two parts to that. I think Roger, you know, hit the nail on the head in terms of when you really get into looking at minimum load, if you don't have the raw data. You've got to do an extensive review of the customer population, you know, the fusing, the reclosers, all what you've sized things over time.

I think the dilemma with that is estimating minimum load in order to meet a very quick fast track time frame becomes very difficult in those short time lines, because we also have to recognize as we move forward to get actual minimum load data, those decisions are made by every state regulatory body to approve those investments or not.

We just need to recognize that from that perspective, it's going to happen over time, but it will end up being, you know, that particular state that authorized that particular distribution, getting utility approval to spend money in this way or that way, right?

That's where, that's how you're going to fund it, if the solar development community isn't going to fund it. So that's where we have to really understand it will happen. So estimating minimum load is still, and as Kevin said, I think clearly when you have the pre-application report, because we do those as well in the northeast, which are very effective, you can provide it.

If you don't have it, and they roll into the other studies, then you can go ahead and try to get it, because we do come up with -- we do estimate the minimum load when we're doing the impact study, so we can understand do we need to be careful of islanding and that sort of thing.

MS. KERR: Ms. Nicole.

MS. NICOLE: So I would just make the point that we are talking about minimum daytime. So that's kind of the context of the conversation that we're talking about, and also not get away from the idea that it's also in the context of line segment versus circuit or feeder level or transformer level.

You know, it seems -- from my understanding, it seems that the minimum load data is available at, you know, for folks who have SCADA systems or other sort of digital applications. They can easily get that data. So it's not necessarily that that's a prohibition to moving forward.

However, what I like to think about is kind of the difference between when we mentioned daytime minimum load in the paper, it's kind of in your mind separating out the difference between the interconnection screen and a short-term solution for improving the screening process, versus solutions for integration of solar.

It's two, in my mind, it's two very different topics. So right now the 15 percent is an estimation, and so can we improve upon that with, you know, as Mike Sheehan said, with validation of measurements in the field, or more transparency on data that's already being collected, or potentially collecting more data?

I think those are all potential options, but they should be focused on the conversation of addressing the problem of the accuracy or, you know, usefulness of that particular fast track screen.

When you talk about integration of solar, you know, which we do every day at EPRI, it's a matter of understanding the complexity of the system, and frankly what we're looking at is it's not so much a load data or megawatt, PV megawatt data.

You're looking at a host of different characteristics and the interaction of those characteristics, how load changes over time or what estimates you're making, what data you have available.

So what we would like to do is get away from sort of 15 percent or 30 percent or 100 percent, and try to talk more broadly about what we can do on the integration side. That would then sort of feed some of the interconnection policies, in a way that everybody's happy with.

MS. KERR: And Mr. Fox.

MR. FOX: Thank you, Leslie. I just want to take a moment to echo what Tim said, because I think he really kind of got at the nut of the issue here. The issue really in my mind is how long does it take to estimate the minimum load.

I haven't really heard anybody speak forcefully against relevant, minimum load being a relevant criteria in the interconnection process. Roger talked about the fact that if they were doing an interconnection study, a system impact study, they would take a look at minimum load, and they would have additional time, and certainly, you know, the additional funding through interconnection study costs, to be able to take a look at minimum load.

I think the issue really here with the

supplemental review is, because the supplemental review I think this got lost a little bit earlier on the first panel, is you know, the initial review screens are kind of a thumbs up/thumbs down sort of approach.

What California did with supplemental review really operates very differently. It allows a lot more engineering discretion and judgment to be involved with the application of reliability, safety, power quality screens. Also, one of those considerations, then, is minimum load criteria.

So to the extent that is a relevant consideration in the process, in California is was felt that the exercise of the engineering judgment around reliability, power quality and safety sort of issues could be coupled with the calculation or estimation of the minimum load, so you could do a sort of quick, second look for systems that failed initial review, and say within 20 business days and with a $2,500 fee, yes, this system can pass without additional study, or no, it needs additional study.

But there's a fair amount of discretion there to apply engineering judgment, so we can avoid the sort of, you know, bad case scenarios that a lot of people brought up on the first panel. You know, I've talked to a number of utilities about this, and a number of them have echoed the belief that they don't necessarily want every single project to go to study either.

So I think really at the core, what we're talking about here is is there some subset of projects that may fail the initial review screens, that don't necessarily require full study? Because if there is, then it makes sense for everybody involved to pull those out, and create a process that allows them to be addressed quickly, and at a reasonable cost, without a full study being required.

MS. KERR: Well with that, we're going to end this panel. Thank you very much for a good discussion, and we will be back in 15 minutes. Again, for folks who are leaving, I would just like to remind you that we are taking written comments for 30 days on the issues brought up in this technical conference. Thank you.

(Whereupon, a recess was taken.)

MS. KERR: All right, welcome back to the last panel. Our last panel of the day is on the "Review of Upgrades" required for interconnection.

Our panelists include Jim Torpey from SunPower Corporation, on behalf of SEIA; Rick Gilliam from The Vote Solar Initiative; Dan Adamson from SEIA; Roger Salas from Southern California Edison; and Steve Steffel from Atlantic City Electric; and Steven Herling from PJM.

I would like to invite our first panelist, Jim Torpey, to give his opening statement.

MR. TORPEY: Thank you, Leslie, and thanks to FERC staff for convening this discussion on barriers to interconnecting solar and distributed generation.

My name is Jim Torpey. I am the Director of Market Development at SunPower. SunPower is a manufacturer and developer of solar-based projects in California, our headquarters in California.

A couple of things that are relevant. For one, I have worked for 20 years of my career for a public utility, and I will just say that I really respect all the things, and the difficulties and the problems that you've heard about today. And I also have seen the tremendous ingenuity and ability to solve problems at the same utility engineering groups, and I am sure that a lot of these things that we've talked about as we work together can be solved.

SunPower has either interconnected or is in the process of interconnecting about 1200 megawatts. So we do have some experience and some of the things that I'll be talking about are based on that experience.

We've heard today appeals to work together with utilities to improve interconnection and reduce costs, and we are certainly very interested in doing that. And I think what I am going to talk about and what we'll talk about on this panel is at least our attempt to start to work that out, work out one process for how to do that.

Reducing costs is very important to us, both from the standpoint of reducing time and effort that the utilities have to do in order to review interconnection requests, and then also in terms of the time and money costs of interconnecting and making sure that those are appropriate for meeting the needs of the grid.

I think one of the things, when somebody asked on an earlier panel what are some of the costs involved in these interconnection studies, the thing that is really important to understand from the aspect of solar development is time is money. And it's something that if you put a project into what we consider to be sort of a black hole of an interconnection request and don't know when it's going to come out, an answer, or how much that is going to cost, it is really something that makes a project very difficult to finance. And you're basically really making that project a lot more, not only difficult to finance but more expensive.

And so I think it is in everyone's interest to try to make that process work a lot better.

What we are seeing is that there is little transparency--and this is again from the perspective of a solar developer. We are seeing little transparency regarding each public utility and/or transmission owner's technical requirements for interconnection.

In practice, each is different and each may change over time. From our perspective again, once we submit a project oftentimes it seems like it falls into a black hole. You don't know what's happening. You don't know where it's going. You don't know how much it's going to cost.

And what happens is that we also see sometimes some of the requirements appear arbitrary and discriminatory, and that individual developers are sometimes asked to take on costs for technical solutions that appear to be either excessive or unnecessary as related to a specific project.

I think later in the panel Rick may give you some more specific examples about that. But in any case, there's really no effective process in place today for adjudicating these disputes concerning reasonable and alternative solutions for maintaining distribution reliability and safety.

And again, it is not our intention to get around anything that has a safety or a reliability impact. But sometimes there are different alternative solutions and ways to do it a lot better than--or at least from our opinion, there should be some process for figuring that out.

So what we are really talking about is presenting an approach that's an improvement to transparency and also to process.

So the first step one, we need to know what the process is for each utility. And sometimes you've heard a lot from the utilities today, but not every utility is as completely upfront and able to work as well as some of the utilities you've heard today. So we are really talking about a process that is required across the board in many cases.

We are really looking to require utilities to publish what their requirements for such items as voltage control standards, when a transfer trip is required, et cetera, et cetera, a lot of technical requirements. Sometimes we don't even know what they are until after the fact. We would like to see those up front. As well as a time frame for which they say we can develop a project under X amount of time, and these are the time frames. And then we should have the right to challenge those if they are unreasonable.

The second thing is to define what some alternatives are in case there is a dispute over what the best solution is. So cases where the developer believes that proposed upgrade requirements are unreasonable and not supported by the facts, developers should have the right to commission at their own expense a professional engineering report outlining alternative solutions to identified issues.

And then we can go through a process--this is one process that we're suggesting, but we're not saying this has to be prescriptive. But in any case, a utility could either accept the developer's report, or they could say, no, we don't really accept your report. And so what we would do is go to a third party.

You'd have an independent third party who would then look to present the facts, by reviewing both the utility report and also the report of the individual developer, and then come up with an opinion. That opinion would then be--although the final decision would remain with the public utility, the utility will be expected to give substantial weight to the findings and recommendation of the third party expert when making its final interconnection decision.

In the event the utility does not accept the expert findings and recommendations, it must provide the applicant a fulsome explanation of the factual basis for not accepting the third-party recommendation.

I know there was a question about whether it would be a viable alternative to have a comment section, as is done in the large generator interconnection procedure. In conversations with developers familiar with the practices of public utilities and the LGIP procedures, the general consensus is that the opportunity to provide comments is somewhat perfunctory because the public utility is under no obligation to seriously consider the alternatives being presented by the developer's engineering consultant.

By adding an objective third-party expert's input, the expectation is that there will be a higher standard established for considering and incorporating the objective engineering input.

Thank you, very much.

MS. KERR: Thank you, Mr. Torpey. And now let me move to Mr. Gilliam.

MR. GILLIAM: Thank you, Leslie.

My name is Rick Gilliam. Just by way of background, I spent a number of years here on the FERC staff, actually, at the start of my career. I worked for a utility for a dozen years. And then went to work for a competitor of Jim's here, SunEdison, and worked there for a number of years. And now I'm with Vote Solar.

Vote Solar is a nonprofit 501(c)(3) organization that advocates for positive solar policies to bring solar into the mainstream across the United States.

I appreciate the opportunity to speak today, and the comments I have will address the interconnection standards first established as part of Order 2006.

As you know, these have been used by many states as a model to develop similar interconnection standards for connections of small generation to the distribution grid. As such, these rules have set effectively a minimum standards for SGIP on the distribution grids.

As we have heard earlier today, the lack of consistency, the costly and lengthy process, is a problem for solar developers. Our goal in making these comments today is to help promote a clear and predictable path to interconnection for distributed generation.

In my experience, for projects that do not pass the Fast Track screens, utility facility studies have found a diverse set of assets and costs required for the interconnection. In addition to expected and quite normal costs such as reconductoring, transformer upgrades, and so forth, upgrade requirements have been imposed that include exorbitant and sometimes surprising costs of things like extensive telemetry equipment, life-of-asset O&M costs as part of the upgrade, and income taxes included in these estimates.

It's not at all clear that the assets identified in these upgrade requirements are the minimum required to resolve the concerns and inclusions of the system impact study. And we all need to remember that these costs, one way or another, ultimately will be paid for by the utility ratepayer.

Additionally, some transmission providers--and I use that interchangeably with IOUs--have played a type of Price Is Right game with the feasibility study in which a quick turnaround is offered if the developer accepts a facility's estimate with little supporting documentation or, Door Number Two, wait longer for the unknown system impact and facility studies which may result in higher costs.

While such an offer may be made in full good faith, it offers the potential for gaming, particularly when solar developers operating in a highly competitive marketplace are anxious to move projects along as quickly as is feasible.

This risk is compounded by the serious information imbalance between the utility and the project developer. The developer has little upon which to base an informed decision. The preapplication report that's been discussed several times earlier today in Rule 21 we think is a good step forward in that regard.

Overall, in our view there's insufficient transparency and accountability in the interconnection standards. Order 2006 did provide for some relief in Section 3.5.4, but unfortunately the wording of the section leaves the utility as the party with the ultimate decisionmaking authority. And as Jim said, it provides little motivation for the developer to challenge those findings if there isn't an opportunity for either a third-party review or ultimately an arbiter such as a public utility commission.

The supplemental notice that the FERC issued asked for us to address a few additional questions. So just to cut to the chase:

In our view, an independent third-party review of upgrade requirements would help generation developers to have confidence in the determination of upgrade requirements, but only if there's an opportunity for backstop regulatory oversight.

It is unclear whether the written comments contemplated in the second question, the LGIP, would be made to the transmission provider or to a regulatory body. If it's to the transmission provider, I agree with Jim that there is not much motivation on behalf of the developer to follow that path if the transmission provider is the ultimate decision maker.

Indeed, we believe the feasibility study itself should be subject to the same opportunity for third-party review of potential adverse system impacts with a right to appeal to the regulatory body as the final arbiter.

You asked for some down sides. I can get into that in a few moments. The cost of engaging a credible engineering firm to review potential system impacts and upgrade requirements could be a challenge, in that the firms that are out there often are retained by utilities for work, and there may be a conflict of interest.

And the size of the projects that generation developers in the solar space typically do are considerably smaller than other opportunities that utilities may be able to offer engineering firms. So there may be some reluctance on the part of such firms to engage in that process.

Having said that, we think it is still important to have that opportunity to engage a third party.

Finally, I would like to ask the FERC to continue its original plan to review these interconnection standards on a periodic basis so that we can stay current with the fast-changing technologies.

Thank you.

MS. KERR: Thank you. And Mr. Adamson.

MR. ADAMSON: Thanks. So we're talking upgrades. I think it's good to at least spend some time on it, because we have spent so much time on minimum load and Fast Track--which not to discount that; I think they're very important--but this upgrade issue is important.

Let me just stipulate up front that, notwithstanding the various anecdotes that we've brought to your attention, that I think the recommendations that utility engineers make on these sort of upgrades are offered, you know, based on their expertise, and they're offered in good faith. I think they're trying to do their job, which is not an easy job, and part of it is keeping the lights on.

But I will also stipulate that utilities are not infallible. They have not discovered truth. And so sometimes they make a mistake in terms of an excessive upgrade requirement. And I think it's really expecting a lot of the utility to be an impartial arbiter over a situation where its own self-interest is at stake. And this is a familiar situation for FERC, obviously, you know, in your quest to have J&R transmission access.

So I mean there is a little bit of a conflict of interest. You know, generally the unit to be interconnected is competing against a utility in the wholesale market. And I also think, you know, having also done a lot of work for utilities and spent time with utility clients in a prior life, you know, the addition of DG to a circuit does make a utility system engineer's life more complicated. You know, that's just a fact.

And so it's hard for the utilities to always come up with what we would view as a reasonable and cost-effective upgrade solution. And so we think the remedy is to bring in a third party, and SEIA's petition proposes that at the request and cost of the applicant, that a third-party expert reviewer would be brought in; but that the utility would still, as it must be, be the final decision maker. I feel that very strongly that, you know, utilities are accountable for reliability. And so in the end it is their decision. But, that they would be required to give due weight to the report of the independent expert.

And I think just bringing in somebody who is impartial, or at least a third-party expert, could really help solve this problem. You know, SEIA is not wedded to a particular process, but we are wedded to the notion of third-party review and some type of orderly process. Because the upgrade issue is right up there with Fast Track in terms of the concerns that our members have.

And that's all. I'll finish up in three minutes on that one.

MS. KERR: All right. And Mr. Salas.

MR. SALAS: I would like to again thank the Commission for the opportunity to participate in today's conference, and to offer SCE's perspective on SEIA's proposal that the SGIP be modified to provide for a third-party expert review of upgrades identified as a requirement for an interconnection.

SEIA's proposal requires transmission owners such as SEC to give substantial weight to third-party experts' findings and recommendations for the identified upgrades and to provide a fulsome explanation of the factual basis for rejecting the expert's recommendations.

It is SCE's position that qualified third-party experts can provide meaningful input during the interconnection process. That being said, we respectfully oppose SEIA's proposal because it will not facilitate meaningful dialogue between the utility and the third-party expert, but will instead likely create additional delays and disputes during the interconnection process.

During my prior panel discussion, I explained that the SGIP is working as intended in SCE's service territory in that it has not unduly discriminated against solar developers. What I would like to expand on upon here is how the current SGIP already allows for meaningful dialogue between the utility and the interconnection customer with respect to upgrade requirements.

As indicated previously, we have studied nearly 600 interconnection requests in the last three years under the SGIP. In our experience, the process works well--but only when the third-party expert is familiar with typical distribution system standards and practices.

Under the current process, applicants are encouraged to bring, and often do bring, engineering experts to the study results' meetings to discuss the upgrade requirements that SCE identified during the study process. During these meetings, we sometimes hear suggestions regarding modifications to proposed distribution system upgrades.

We are not averse to implementing the suggestions as long as the proposed changes meet SCE standards in terms of design, construction, operation, and maintenance, as those standards have been reviewed and approved by SCE experts in these respective areas.

This is crucial as distribution upgrades and interconnection considerations must comply with our company's standards to ensure safe and reliable operation of our system for our employees and customers.

Nonstandard equipment design or construction may make hazardous safety conditions, problems operating the system, or longer delay times during a service restoration during an emergency.

We explain our comments on SEIA's proposal that we believe that an outside expert can provide a meaningful input during the interconnection process, provided that the expert is familiar with our distribution system, and in fact we have had instances where applicants' expert engineers were familiar with our systems and they suggested appropriate changes that actually did reduce their costs significantly.

We also believe that the applicant who hires such experts will benefit from involving the expert at the start of the application process, as opposed to waiting until after the studies have been completed and the resources have been already submitted--provided to the applicant.

Waiting until the studies are provided will only serve to further delay the process and potentially increase the cost to the applicant.

In conclusion, we respectfully submit that the SCIP works well for all applicants who take the time to hire a third-party expert that is familiar with the distribution system standards and practices. We hope that the perspective that we have provided here today is helpful to the Commission and some of the participants and we look forward to further discussion.

That's it.

MS. KERR: Thank you. Mr. Steffel.

MR. STEFFEL: Thank you. Steve Steffel representing PEPCO Holdings, Inc., and the three utilities we have, Atlantic City Electric, Delmarva Power & Light, and PEPCO.

The first thing I wanted to mention, just to start with studies and the upgrades, looking back in 2011 we had about 1700 applications, 76 megawatts added to the system, and there were about 35 studies.

Of the 35 studies, a number of them did not proceed to build. So you can see that with that small framework there's not tons of projects that needed upgrades, but of those 35.

The first thing we think about is process. We mentioned that. We've had public forums that would explain to developers the process both on the NEM side and the wholesale side. And on the wholesale side, they run through our ISO, PJM, and Steve Herling will probably touch on some of that. It's a very structured process, including review, reviewing the transmission impacts and so on and so forth.

And we follow that very carefully. We are in a sense sub to them. They are the project manager on those wholesale projects.

The next thing that is important that was mentioned is criteria. And it is true, we have had to develop a lot of criteria for DERs being added into the system. And anything that has been--or is geared to the understanding of the developer, we have put into our public documents. We have some interconnection documents that are on websites. And they're updated yearly, every couple of years. And so we probably have some more things that we've put in.

We actually are putting them right in the studies, some of the very salient points, so that they understand what our criteria is and why we would require an upgrade, and so on. And these are very valid points and we're trying to address those kinds of things right up front so we don't run into issues there.

Currently we've done most of our studies with third parties. And we do make those studies available when they're finished to any developer that wishes to have them, all practically 50 pages of them or so. And we've set down and discussed with all of the projects that have needed upgrades, and we haven't had any that have required, you know, review by a third party yet. I mean, I understand some of the concerns. But we've been able to work through that.

One of the things we're working on in-house, and we've mentioned it, is that we are working on our own time series load flow program with an automated study tool so we can save developers both time and cost. And I think that will be a significant benefit to them.

Now some concerns with third-party reviews. Each utility has its own planning and operating criteria and construction standards based on national and state standards, and best industry practices. And a third party, whoever is reviewing the results of a study, would need to follow those when assessing the recommended upgrades that were put together as a result of the results of the study.

Now it's going to add time and cost to studies. There will be added effort by the utility to explain the study results, study criteria, construction standards, et cetera, and to provide the needed information for the third-party to do the review.

We haven't had to have that to this point. We've had good discussions, and talked with our developers who are putting things in, and anything that they suggested, if we could accommodate them, or if there were options, we made those available.

But the main thing was to build the system to the standards and criteria that we had laid out as a utility. And we do that whether it's an internal project or an external project. We don't build them differently.

So my only concern would be it does add time. It does add cost. All those things have to be explained. And it does open up the possibility for some maybe contention, or whatever, but I don't see it as a major issue because we haven't had too many--haven't had any issues of that nature up to this point.

MS. KERR: Okay. Thank you. And Mr. Herling.

MR. HERLING: Good afternoon.

My comments are related to the projects as they proceed through our interconnection process, specifically to participate in either the PJM energy market or the capacity market, or both for that matter. This is a relatively small slice of the projects that are connecting in PJM. We have a lot--a very large number of net energy metering projects, in the thousands, or tens of thousands that PJM does not get involved in. We have processed about 600 projects through our interconnection queue.

At this point I think we have about 3,100 megawatts that are either in service or are currently under construction. So from a megawatt perspective, it's a fairly large number. But from a project perspective, I think in New Jersey alone we have had 14,000 requests under net energy metering, and in all of PJM we've only had about 600 requests to get into our markets.

Now procedurally we use the same process that we use for large generators: feasibility study, system impact study, facilities study, and ultimately execution of a Wholesale Market Participant Agreement, or an Interconnection Service Agreement.

The difference really is we have screening tools that we use to determine whether or not there will be network impacts that need to be considered--meaning higher voltage, 100 kV and above impacts.

The solar projects that we look at are typically in the range of about a half a megawatt up to 20 megawatts. So by and large we have seen very few impacts on the higher voltage transmission, and when that is the case we then move the project to the transmission owner for a look at the distribution and the subtransmission voltage levels--12 kV, 34.5 kV, and such.

The vast bulk of the analysis for those projects has to be done by the distribution owner. We just don't have the involvement in those facilities. The bottom line is, we still manage the process with the transmission owner and the interconnection customer. We still facilitate all of the meetings around the different study results. In many cases, the interconnection customer works with a consultant throughout the process. So we facilitate meetings. We take comments at each stage of the process, and we'll factor in their suggestions into any upgrades or results that perhaps we need to take a different look at.

The bottom line is, I provided in my materials a map. There is a significant number of projects, if you look at the geographical areas. So we still do have to manage the rights of the different projects since they are trying to connect back into our markets. So the study process still has to follow the timeliness that are dictated in the PJM Tariff in terms of, you know, the completion of the studies, and the amount of time that the developers have to review the results with PJM, with the transmission owner and their consultants, and get responses back to us so that they can then move on to the next stage.

At this point, we have had, you know, as I said, a fair number of the interconnection customers using this meeting process to review the study results, to review the upgrades with their consultants. I'm not sure that we need to have a third party completely separate from the customer and their consultants and PJM and the transmission owners. It seems so far that we've been able to get through the review of the upgrades and the projects that are moving forward have been able to identify the required upgrades and move on.

We have so far had about a 65 percent dropout rate among solar projects. The dropout rate in the big queue is probably closer to 88 percent. But that could just be because the solar projects are newer to the queue. We have still a couple of thousand megawatts of projects under study. So by the time that wave comes through, it may creep up a little bit.

The bottom line at this point, I think the process is working reasonably well. We are managing to keep it reasonably close to the tariff timeliness that are specified. And we have gotten a fair number of projects connected to the system.

Our experience is improving, as are our transmission owners, in terms of the types of analyses that they have to perform. And I think generally it's working pretty well at this point.

Thank you.

MS. KERR: Okay. Thank you. I guess the first question I have is: How would the independence of the third-party be assured? Whoever is interested in answering that?

MR. ADAMSON: Could you repeat the question?

MS. KERR: How would the independence of the third-party reviewer be assured?

MR. ADAMSON: Well, I think--

MR. DAUTEL: I think, just for some background, we got some comments that there was some question about whether the independence could be assumed in these cases.

MR. ADAMSON: You know, all I can speak to you is to what SEIA specifically proposed, and we proposed that essentially that you as a developer be able to bring in what you considered to be an independent third-party reviewer.

We didn't--basically, they are able to come in and hire their own experts. So I don't think there's necessarily some type of litmus test. But obviously if you pick somebody who is viewed as, you know, biased, that expert is not going to help you nearly as much as somebody who is viewed as playing it straight and somebody who is respected by both sides of the equation.

But we weren't thinking that there would be some kind of a specific standard. I can't speak--Jim offered some other thoughts, but--

MR. TORPEY: Yes. So this is speaking only for SunPower, not for SEIA, because this is not a SEIA petition, but I would envision something where you would have something like when you choose an arbitrator in a land dispute, or an appraisal dispute, where you have different parties suggesting people. And then you pick from a common group.

In other words, I would see something that this expert would be somebody who would be approved by the utility and approved by the developer. And the idea would be to have a sort of a cadre of people who you would choose from, just as you do appraisal firms. And again, it would be important I believe from the utility perspective to have that person vetted so that they would understand something about the nuances of the system, et cetera, so that you wouldn't just be, you know, kind of plucking people out of the air; you would be plucking people, or sort of engaging people who have more experience and at the same time would be recognizing from the utility--from the developer side some of the nuances, or some of the alternative ways to come up with solutions that might be a little more cost effective.

MS. KERR: Dan?

MR. ADAMSON: Yes, you know, I also said I think we're flexible on this issue. So I think what Jim is talking about falls within the ambit of the kind of idea that SEIA is supporting. We just want to get some type of third-party expertise involved. There's different ways to do it.

MR. QUINN: Could I just ask a follow-up? Can the ISO or the RTO, if there is one in the area, serve that purpose of independence? What Mr. Herling was talking about sounded a little bit like you were facilitating meetings between the developer company and the interconnection customer. Do you feel like you were applying engineering judgment in facilitating those meetings? Or were you mostly there as a facilitator in kind of this arbiter role?

MR. HERLING: Our ability to do that is fairly limited. We do facilitate those meetings. At higher transmission voltage levels I think we have a lot of expertise that we can apply to discussion of what upgrades may be required. But once you get down into the distribution system, it would be probably better to get firms that have that expertise specifically. So I don't think we could provide that level of expertise to provide that function.

MS. KERR: Mr. Torpey?

MR. TORPEY: I just want to be clear about one thing. First of all, what I'm not suggesting is that you don't have a third-party person engaged at all in the conversation from the very beginning.

I think any solar developer who has got any concept of how to get things done will be sitting down with the utility and PJM as one of the first things they do, with an independent consultant--you know, with their own third-party, or it could be someone from within the company--but engineering expertise to sit down and talk from the very beginning on how to put together the interconnection study.

So it's not let's wait to the end and then kind of make this process--kind of force this process. So that's the first thing.

And the second thing is this need for a third-party person, I think as Steve said and other people have said, many times this works very well and it's not necessary to do this. This would be sort of an extraordinary circumstance where there was a real dispute.

And what we're talking about is a lot of these costs being borne by the developer. So no developer is going to go through this whole process unless there's really something significant at stake. So this is not something that would be the norm. This is something that would be more, in my opinion at least, more an extraordinary or an unusual event.

But at least it would give a process, and it would provide a mechanism for this kind of third-party opinion to be codified and provide more of a record for a real codification of what the dispute might be.

MS. KERR: Mr. Herling.

MR. HERLING: Yes, I just--I agree with Jim's comment about the importance of having the developer bring expertise with them, consultants or staff, whichever, all the way through the process.

And honestly I think that will serve in most cases to bring the same value that a third party would bring. We have consultants all the time challenging the upgrades that are identified, and suggesting alternatives, and we'll ensure that they go back and look at those and we'll determine whether it makes sense or not.

To have a truly independent third party, we don't have any experience with that so much in the interconnection process, but in our regional transmission expansion planning process we do now accept proposals from independent, nonencumbent transmission owners that they would like to develop in PJM.

We will hire firms, siting/engineering firms, construction firms, to do estimating and to evaluate the risks associated with siting and regulatory, et cetera, for those projects to kind of balance the estimates that the parties are providing to us.

We're using the same firms that our transmission owners are using, and that the nonencumbent developers are using. So what we typically do is have a bunch of them under contract, and in a given geographical area we try to get somebody who is not already working for the nonencumbent or for the transmission owners. And it's a challenge. And let's face it, they're not making nearly as much money working for PJM as they will eventually for, you know, the successful proposer of one of these projects.

So it is a challenge to find a true independent, and they often have to ensure that they're working with a crew where they can put a wall up between other parts of their business.

MS. KERR: Okay. Thank you. Mr. Salas.

MR. SALAS: Yes. I would like to address very quickly the--you know, as I stated before, we have the examples in the current process where applicants bring experts. I can think of at least three off the top of my head where the cost of interconnection is significantly high, so we're not talking about your simple little interconnections, but distribution upgrades, long-line extensions. And under the current process we already have the ability and the applicants have that ability to bring experts to basically challenge or provide for alternative solutions.

And under those types of projects that I'm thinking about, I mean we are looking at alternative ways to present the substitution upgrade, or alternative ways to do a significant line upgrade which saves the applicants millions of dollars.

So that process is already in place. And I just find it difficult that we're talking about adding an additional component that can't really not--I'm not sure it's really going to serve the needs of, you know, SEIA is proposing.

MS. KERR: Thank you. I guess I would like a little more information on how the proposal is different from the current provisions in the SGIP, if one of the first three panelists would address that?

MR. ADAMSON: In one respect, it's diff--at least the SEIA proposal, not the Torpey SunPower SEIA proposal--it just says that the utility must give due weight, or substantial weight to the conclusions of the expert. So that is a significant difference from the status quo.

MS. KERR: Okay. Mr. Gilliam?

MR. GILLIAM: I talked about actually regulatory oversight. I think Jim framed it as essentially what we used to call a "technical master" on the engineering side.

This is not a pervasive problem, but there is an issue that has come up a number of times with my former company, and my sense was that--and with a lot of regulatory experience--over time when there's an opportunity for review of assumptions that are made, review of costs that seem unusual or in some cases maybe exorbitant, over time the regulatory process results in a better, narrow, defined set of costs and cost elements.

And I don't think that opportunity is captured in the SGIP today. There is a dispute resolution process in Section 4, which of course is related to transmission providers because it relates to the FERC. But in terms of setting an example for state standards, in my view some additional oversight is needed whether it's a third-party independent arbiter such as a technical master, an engineering master that would be the final decision maker, or an opportunity to actually take the dispute to the state agency.

And I realize that that's not your purview, but that's something that we see as needed. Thank you.

MS. KERR: Okay.

(Pause.)

I'm just taking a minute to look at my notes. I guess, are there other options than what's been talked about here? The LGIP provisions seem to be not so popular with the panelists. Are there other provisions that you've thought about that should be considered?

(No response.)

MS. KERR: Seeing none, I do have a follow-up--oh, I'm sorry, Mr. Torpey, go ahead.

MR. TORPEY: This is not quite to the point, but I think in terms of what you heard, there are a number of utilities and ISOs who essentially are establishing best practices, and being very inclusive in their processes of welcoming developers to bring in technical people, et cetera, publishing their timeliness so it's very transparent what those timeliness are, and when we can expect information back.

But unfortunately our experience has been that that's not true of everybody. So essentially when you say what else? What are our other alternatives? The alternatives that would be very helpful, if there was a requirement that everybody did what Steve is talking about doing in terms of making their requirements, their technical requirements, transparent and so everyone would know what they are. At the same time, the timeliness and when people can be expected to get answers and get studies back, and the process that they should go through in order to make sure that that moves sufficiently. That would be very helpful, and I think a lot of the difficulties that sort of people are sensing as developers with the process would really be addressed by essentially make sure those best practices are done throughout the country.

MS. KERR: Okay. So just to follow up, you're talking about what Mr. Steffel talked about in his opening, the different practices?

MR. TORPEY: Yes, the criteria that's established, and what are those criteria, and how have they dealt with these situations in the past. And, you know, when would they require something like a transfer trip, or some kind of the technical requirements; that different utilities vary on. So it's not that every utility--I'm not suggesting that every utility would have to adapt--adopt the same set of standards. But what I am saying is that, whatever those standards are, they should be published and everybody should know what they are so a developer knows what they have to address beforehand and doesn't have to wait three months to hear it.

And again, not everybody is doing that. But there are some utilities that tend to do that. And that's the sense sometimes that we put development interconnection proposals in and it ends up being a black hole, and no one knows what is happening to it. And maybe it comes back six months, and they say you didn't do X, Y, Z, and if we would of known it beforehand, that wouldn't have been an issue.

So it's a matter of transparency, and it's a matter of knowing, you know, what the timeliness are for the development process.

MS. KERR: Okay. So we have talked about this some, that revising, or allowing for more third-party review of upgrades would add cost and time to the interconnection process. And I guess I want to get a feel for what we think those timeliness would be.

What would be acceptable? If anyone would like to address that? Mr. Adamson?

MR. ADAMSON: Well I think as developer you are only going to resort to the third-party process, or expert, if there's a lot of money on the table.

I mean, if somebody is saying--the utility is saying you've got to replace that transformer or that substation, or something, you know, that cost $1 million, you know, you may save you and your company and your customers quite a bit of money by spending some money on an expert. So I think it just depends.

And you might get through your situation quicker, too. I mean, you know, you wouldn't want to--that's what Jim was talking about earlier. I mean, this is not something you would just kind of do routinely; you'd be doing it if you were in a crisis situation with a utility that, for whatever reason, you felt was being intransigent.

MS. KERR: Okay. Mr. Gilliam?

MR. GILLIAM: I just want to make sure we're differentiating between the different types of third-parties here. I think there's the third-party that would be in a sense the final arbiter of an engineering dispute. The other type of third-party that at least I've referenced a couple of times is one that is retained by the developer to review the interconnection feasibility study, system impact study, and so forth, and that might create that dispute to begin with.

In some cases, while it would be great to have--and Dan is right, that there's a cost issue here--if you have a project that's relatively small, on the order of a couple of megawatts, it's hard to know when the right time is to bring in a third-party engineering expert until you see either some initial indication of the concerns of the utility, the potential upgrade requirements, and in relation to the cost of the project if it seems out of line, so to speak, then that's when the developer may want to either bring in a third-party engineer just to hire for itself, for its own edification, or to cancel the project. And that's usually the point in time that that decision is made.

MS. KERR: Okay. Mr. Herling?

MR. HERLING: I think probably the only thing I can add, my concern would be we get a lot of projects in very close electrical proximity to each other, and they all have pending rights with respect to our marketplace.

So if we're talking about some form of an arbitrator, you know, at the end of the day when you have a dispute that you can't resolve otherwise, whatever we do we have to be able to do it quickly so that the project that has the issue is not holding up, you know, a handful of projects behind them in the queue who may be anxious to move forward with their projects as well.

It would concern me to bring someone completely new to the process in at the tail end and have to go through months of getting them up to speed, and some form of hearing, so that they can then pass judgment on the results that have been developed. And then we have to go back and, you know, provide some weighting to those results and determine whether or not a different result is justified.

Everybody behind that position in the queue is going to be impacted adversely.

MS. KERR: Mr. Salas?

MR. SALAS: Yes. I just wanted to re-emphasize again, and perhaps it is that it's a practice of Southern California Edison, where we already provide that ability. Perhaps other parts of the country don't do that, but at SCE you can bring a third-party and talk about substation problems, and talk about alternatives, and talk about different ways to mitigate the problem.

So adding additional steps in the process, as Steven indicated, can potentially put you in a situation where you are waiting for this third-party expert to make a decision. In the meantime, you have other projects that are in back that are waiting for this decision to be made.

So there's probably, you know, for the amount of projects that I have seen in the last three years that have this potential condition that could be resolved by already having the language in the tariff, it seems to me that adding this additional language, or additional provision can actually provide additional delays that may affect a lot of other, more projects than actually providing the benefit that really is already there, you know, as part of the process itself.

MS. KERR: Okay. To come back to the LGIP comment process, I guess I would like to address it to the utilities. We heard from the solar panelists. Does that process, if you're familiar with it, provide meaningful input? Or do you have any other comments on that process? Mr. Herling?

MR. HERLING: YOu know, I think there's plenty of opportunity in that process for review and input, and many of our developers come, again, with consultants and have over the years offered all sorts of alternative solutions to the ones that we have developed between PJM staff and our transmission owners.

So I think that process has worked very well. The application of the same process to the smaller projects, the primary shift is that the upgrades are now down on the distribution system. So my staff are certainly involved, but the expertise that we can bring to bear is a slightly different focus there.

We don't have as much expertise in distribution as we do in transmission.

MS. KERR: Okay. Thank you. Mr. Salas?

MR. SALAS: Yes. As I stated, you know, the current process works. But now adding this language that's going to apply to all the projects, and now you have to wait 30 business days after we provide the study, and then we have to wait 30 business days for the applicants to provide comments, it really is going to create a delay on all the projects.

By trying to help a few projects here and there that have those problems, you are going to create a delay on all the projects. Because now you have additional language there that we need to comply with.

Again, going back to the fact that we already have the process in place that addresses the condition itself, the problem, and I don't think you need additional times to actually add additional delay.

MS. KERR: Okay. Thank you. Mr. Gilliam?

MR. GILLIAM: Yes, I think I could just say as a practical matter, we are not looking to delay the process at all. Any delay adds cost, and for solar developers it makes a project much more difficult to finance. So I think the narrower thing we've been discussing outside of the LGIP process is the potential for an engineering master, which potentially could add some delay to some limited number of projects. But I think all of us have an interest in working together to keep those delays to an absolute minimum.

MS. KERR: Okay. Mr. Steffel?

MR. STEFFEL: Most developers come to us with the experts that are doing various types of electrical engineering work for them. So it would seem to me that most times those experts that they have as part of their team can act as that commentator for them, whether they feel there's something out of line with what the utility is requiring.

And then they can already provide that feedback. And they are normally on the calls that we have when we share results. We have meetings at the company with them when things are starting to move ahead. So there's plenty of dialogue there.

I'm not sure what another engineering party would bring to the, you know, benefit the whole project.

MS. KERR: Okay. Thank you. I don't have any other questions. Does any of the staff, or do any of the panelists want to say anything to wrap up?

(No response.)

MS. KERR: Okay. Well I would like to thank everyone who provided their input today. I know some of you travelled a long way. We really appreciate it.

We have heard a lot of discussion about how small generator interconnection is increasing in both the number of applications and in the amount of generation. We have also heard a lot about how the existing small generator interconnection procedures and agreements could be improved. Some of the suggestions have included creating more transparency in the supplemental review process, and providing developers with information to clarify siting decisions.

Some panelists have suggested more time and opportunity for current processes to address issues, while others state a need for guidance now.

Staff will be reporting to the Commission its views on the ideas expressed today, as well as any comments that are filed in this proceeding. We encourage those submitting further comments to be specific regarding potential changes to the Pro Forma SGIA and SGIP, as well as any comments on the types of processes the Commission could us to achieve potential reforms. These comments are due in 30 days, on August 16th, in Docket Number AD12-17-000.

Again, thank you for coming, and this concludes today's technical conference.

(Whereupon, at 3:48 a.m., Tuesday, July 17, 2012, the technical conference in the above-entitled matter was adjourned.)

Document Content(s)